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Division of Environmental Services
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Pierre, SD 57501

RE: Comments on Big Stone II Draft Permit and Statement of Basis

Dear Mr. Rombough:

I represent the Sierra Club, and I am writing to submit comments on its behalf regarding the South Dakota Department of Environmental and Natural Resources' (SDDENR) draft permit authorizing Otter Tail Power Company to construct of a new 600 MW unit and associated sources (Big Stone II) at the existing Big Stone power plant. The proposed issuance of the permit to allow construction of the 600 MW unit is unlawful for many reasons.

Pursuant to ARSD 74:36:09:01, the procedural requirements governing PSD permits are found at ARSD 74:36:05:08 to ARSD 74:36:05:20.01. ARSD 74:36:05:18 provides that if SDDENR issues a draft permit, any interested person can either submit written comments on the draft permit or request a contested case hearing. At this stage, Sierra Club is filing comments, but it is not requesting a contested case hearing. If, after reviewing these comments, SDDENR decides to issue a final permit, Sierra Club may request a contested case hearing pursuant to ARSD 74:36:05:20.01. It is unclear, however, given that South Dakota is a delegated state, whether a final permit should be appealed to the Environmental Appeals Board pursuant to 40 C.F.R. § 124.19.

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I. THE DRAFT PERMIT COMPLETELY FAILS TO ADDRESS $PM_{2.5}$ AS A PSD POLLUTANT.

Under 40 C.F.R. § 52.21(b)(2), a major modification is any physical change in or change in the method of operation of a major stationary source that would result in: a significant emissions increase and a significant net emissions increase of any ***regulated NSR pollutant***.. The regulations, 40 C.F.R. § 52.21(b)(50), define "regulated NSR pollutant" to mean, among other things, "[a]ny pollutant for which a national ambient air quality standard has been promulgated and any constituents or precursors for such pollutants identified by the Administrator (e.g., volatile organic compounds and $NO_{[x]}$ are precursors for ozone)." EPA has promulgated a NAAQS for $PM_{2.5}$. 62 Fed. Reg. 38,652 (July 18, 1997). The regulations list significance levels for a number of "regulated NSR pollutants," but not $PM_{2.5}$. 40 C.F.R. § 52.21(b)(23)(i). When a significance level has not been identified for a regulated NSR pollutant, the significance level is any emission rate over zero. 40 C.F.R. § 52.21(b)(23)(ii). Although there is no analysis in the application, the permit, or the permit analysis regarding $PM_{2.5}$, a facility of this size will undoubtedly be emitting it in substantial amounts. Consequently, Otter Tail was required to comply with all PSD requirements, including monitoring, modeling, and BACT regarding $PM_{2.5}$, and SDDENR cannot issue a PSD permit for this facility unless this pollutant is properly addressed.

Furthermore, as the definition above shows, "regulated NSR pollutant" includes precursors identified by EPA of any pollutant for which a NAAQS has been promulgated. EPA has specifically identified SO_2 and NO_x as precursors of $PM_{2.5}$. *See* 70 Fed. Reg. 24280, 24282 (May 6, 2005). Consequently, although SDDENR is not requiring modeling, monitoring, and BACT for these pollutants (and, as shown below, erroneously so), it must do so to address $PM_{2.5}$.

We are aware that EPA issued guidance providing that sources would be allowed to use implementation of a PM_{10} program as a surrogate for meeting $PM_{2.5}$ NSR requirements. John Seitz, "Interim Implementation for the New Source Review Requirements for PM[2.5]," (October 23, 1997). The purpose of that guidance was to provide time for the development of necessary tools to calculate the emissions of $PM_{2.5}$ and related precursors, adequate modeling techniques to project ambient impacts, and $PM_{2.5}$ monitoring sites. 70 Fed. Reg. 65984, 66043 (Nov. 1, 2005). EPA has resolved most of these issues. *Id*. More importantly, the guidance clearly contravenes the regulations. In a permitting situation such as this one, where the facility is attempting to avoid PSD review for SO_2 and NO_x, in order to protect public health and the environment, the regulations must be implemented as written.

II. EMISSION REDUCTIONS AT BIG STONE I CANNOT BE USED TO EXEMPT BIG STONE II FROM PSD REVIEW BECAUSE THE EMISSIONS FROM BIG STONE I ARE ILLEGAL

Otter Tail has proposed plantwide emission limits for sulfur dioxide (SO_2) and nitrogen oxides (NO_x) at Big Stone to ensure that the new electrical generating unit and associated sources do not trigger PSD review for SO_2 or NO_x. Specifically, Otter Tail has proposed to cap plantwide emissions based on the average annual SO_2 and NO_x emissions from 2003-2004 at Big Stone I. It plans to reduce SO_2 emissions from Big Stone I by routing the flue gas through the planned wet scrubber at Big Stone II. It also plans to reduce NO_x emissions at Big Stone I by using the existing overfire air system "more aggressively." Otter Tail asserts that with these planned reductions at Big Stone I, post-project emissions from both units will not exceed pre-project annual emissions of Big Stone I. As proven by the attached documents,[1] however, Otter Tail previously made major modifications at Big Stone I for NO_x, SO_2. and PM, and so it must obtain a PSD permit for that unit. Once that permit is obtained, Otter Tail will not be able to generate sufficient creditable reductions from Big Stone I to be able to "net out" of PSD review at Big Stone II. Therefore, Otter Tail must obtain a PSD permit for the SO_2 and NO_x emissions expected from Big Stone II.

A. Otter Tail Modified Big Stone I To Burn Subbituminous Coal Without Obtaining the Proper PSD Permits.

Big Stone I was originally designed to burn lignite coal. For example, a 1998 report on Big Stone I's cold reheat system states: "[t]he major distinguishing features of the Big Stone Station High Energy piping systems (Main Steam, Hot Reheat Steam, and Cold Reheat Steam) are the unusually long main vertical risers. . . . These risers are required to accommodate the height of the boiler which was designed to completely combust lignite."[2]

In August of 1995, Otter Tail replaced the lignite fuel that Big Stone #1 was designed to burn and was capable of accommodating with subbituminous coal as the primary fuel, burning coal from both Kennecott Energy Company's Spring Creek mine and Westmoreland Resources, Inc.'s Absaloka mine.[3] As discussed further below, emissions of NO_x and particulate matter increased at Big Stone I as a result of this change in the method of operation. Yet, Otter Tail made this significant change without obtaining a PSD permit and meeting BACT.

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[1] An index of Attachments is appended to the back of this letter.

[2] "Interim Report Structural Analysis of Cold Reheat Steam Piping System, Big Stone Power Station for Otter Tail Power Company" by Pressure Sciences, Incorporated under subcontract to MQS Inspection, Report No. 98059-001, October 28, 1998 at 3. Attachment 34, Otter Tail's February 2001 Response to EPA's 12/00 Section 114 Information Request, PDF pg. 2570.

[3] July 24, 1997 Notice of Violation issued by the South Dakota Department of Environment and Natural Resources to Otter Tail Power Company) for pretesting evaporation of supernatent in Unit #1 prior to receiving approval), Fact No. 5. Attachment 34, Otter Tail's February 2001 Response to EPA's 12/00 Section 114 Information Request, PDF pg. 1626.

The change in fuel use at Big Stone I would not have been exempt from PSD regulations, either as in existence at the time of the change in the method of operation or under the current PSD regulations. The PSD regulations do include an exemption for a change in fuel use, but that exemption would not apply in this case. Specifically, the definition of "major modification" provides that the following is *not* considered a physical change or change in the method of operation:

> Use of an alternative fuel or raw material by a stationary source which:
> (*1*) the source was capable of accommodating *before* January 6, 1975. . . .

40 C.F.R. §52.21(b)(2)(iii)(*e*)(*1*) [emphasis added].

1. *Because the Big Stone Plant Was Not Capable of Accommodating Any Fuel Prior to January 6, 1975, the PSD Exemption Does Not Apply.*

Otter Tail did not receive a permit to operate from South Dakota until January 14, 1975. (*See* January 14, 1975 permit to operate issued by South Dakota to Otter Tail, transmitted to Otter Tail via a January 22, 1975 letter, Attachment 1.) Further, Otter Tail did not begin commercial operation of Big Stone I until May 1, 1975. (*See* May 5, 1975 letter from Otter Tail to South Dakota indicating its start of commercial operation of Big Stone I, Attachment 2). Thus, Big Stone I was not capable of accommodating any type of fuel prior to January 6, 1975 because the facility was not yet legally allowed to operate. Further, the facility did not begin commercial operations until five months after the January 6, 1975 cutoff for this alternative fuel exemption. Consequently, the alternative fuel exemption at 40 C.F.R. §52.21(b)(2)(iii)(*e*)(*1*) would not apply to Otter Tail's switch to subbituminous coal in 1995 at Big Stone I.

2. *Regardless of Otter Tail's Failure to Obtain an Operating Permit Prior to January 6, 1975, at the Time of the Fuel Switch, the Facility Was Nevertheless Incapable of Accommodating the Combustion of Subbituminous Coal.*

Not only was Big Stone I legally incapable of accommodating any fuel prior to January 6, 1975, but also, at the time of the fuel switch, Big Stone I was physically incapable of accommodating subbituminous coal without other modifications to the facility. Specifically, Otter Tail could not comply with legally enforceable opacity limitations of the South Dakota State Implementation Plan (SIP) at Big Stone I with the use of subbituminous coal. Further, the unit was not physically capable of accommodating subbituminous coals at Big Stone I without incurring physical damage and without being derated.

a. Big Stone Could Not Combust Subbituminous Coal and Maintain Compliance with Opacity Limits.

With respect to opacity violations, Big Stone I experienced high opacity readings on the order of 75-79% opacity[4], well in excess of the 20% opacity limit required by 74:36:12:01 (current codification) of the Administrative Rules of South Dakota, shortly after switching to subbituminous coal. The high opacity readings with the burning of subbituminous coal were no surprise to Otter Tail. When Otter Tail first tested the burning of subbituminous coal, again using Absaloka coal, in the Big Stone I boiler in 1988, opacity averaged at 73%.[5] In May of 1996, Otter Tail wrote to SDDENR indicating the need to make modifications to the existing electrostatic precipitator (ESP) electrical sets and to install a flue gas conditioning system using onsite water sources for water cooling to address high opacity emissions that have occurred as a result of the switch to subbituminous coal.[6] The flue gas conditioning system was installed in 1997 at a cost of $1.15 million.[7] Otter Tail subsequently began using flue gas conditioning agents to reduce opacity rather than onsite water sources for gas cooling.[8] Therefore, Big Stone I was not capable of accommodating subbituminous coal without modifications to the facility to comply with the 20% opacity requirements of the South Dakota SIP. Given, as shown below, that the switch from lignite to subbituminous coal increased emissions of NO_x and PM10, this change in operations triggered PSD requirements, and Otter Tail must now obtain a PSD permit for this modification.

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[4] *Id.* at Fact No. 6. Attachment 34, Otter Tail's February 2001 Response to EPA's 12/00 Section 114 Information Request, PDF pg. 1627.

[5] "Results of the October 1988 ESP Performance Tests at the Otter Tail Power Company Big Stone Plant, Fuel Westmoreland Resources, Inc., Absaloka (Sarpy Creek) Mine, Big Horn County, Montana," by Interpoll Laboratories, Inc., submitted to Otter Tail Power Company, Report No. 8-2636, November 16, 1988, at 3. Attachment 33, Otter Tail's January 2001 Response to EPA's 12/00 Section 114 Information Request, PDF pgs. 96-104.

[6] May 22, 1996 letter from Jay D. Myster, Otter Tail Power Company, to Brian Gustafson, SDDENR. Attachment 34, Otter Tail's February 2001 Response to EPA's 12/00 Section 114 Information Request, PDF pgs. 1484-95).

[7] Attachment 34, Otter Tail's February 2001 Response to EPA's 12/00 Section 114 Information Request, PDF pg. 12.

[8] *See* March 20, 1998 letter from SDDENR to Otter Tail approving the testing of three flue gas conditioning agents, Attachment 34, Otter Tail's February 2001 Response to EPA's 12/00 Section 114 Information Request, PDF pg. 1698, and July 10, 2000 letter from SDDENR to Otter Tail approving the use of flue gas conditioning agents as a minor Title V permit amendment. Attachment 34, Otter Tail's February 2001 Response to EPA's 12/00 Section 114 Information Request, PDF pgs. 1825-28.

b. <u>Big Stone Could Not Could Not Combust Subbituminous Coal and Maintain its Electrical Generating Rating Without Modifications to the Boiler</u>**.**

Big Stone I also was not physically capable of accommodating subbituminous coal. First, equipment had to be modified to accommodate the different characteristics of subbituminous coal versus lignite. Otter Tail's Plant Engineer wrote a memo to the Engineering Supervisor on July 27, 1995, indicating the need to include $500,000 in the 1996 Capital Budget to retrofit the cyclone feed lines to remove the pre-dry system.[9] In the Economic Evaluation attached to this memo, Otter Tail states that Big Stone's primary fuel since startup has been North Dakota lignite and that "[w]hen this plant was designed, the moisture level in the Lignite was high enough to justify a fuel drying system that was placed in the cyclone feed lines."[10] However, the moisture content of the subbituminous coal is much lower than the lignite, even after the lignite coal is dried. Thus, the predry system was removed in December 1996.[11]

Second, the burning of subbituminous coal resulted in lower steam temperatures and affected overall steam production from the boiler, which necessitated significant modifications to the boiler in order to avoid a derating due to the use of subbituminous coal. A 1997 Otter Tail report with technical specifications for boiler repair prepared by the Big Stone plant engineer indicated that "[d]ue to the fuel switch from lignite to subbituminous, steam temperatures have been depressed. Modifications are required to reestablish the design temperatures at normal operating loads. We would also like to establish a closer match between main steam and reheat steam temperature."[12] Prior to the complete switch to subbituminous coal, Otter Tail recognized the need to make changes to the boiler to "get optimum firing efficiency from [the] boiler" in order to "reap the benefits of subbituminous coal firing."[13] This reduction in steam temperatures

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[9] July 27, 1995 memo from William J, Swanson, Big Stone Plant Engineer, to Stu Scheurs, Engineering Supervisor, entitled "Capital Budget Item - Retrofit of Cyclone Feed Lines." Attachment 35, Otter Tail's March 2001 Response to EPA's 12/00 Section 114 Information Request, PDF pgs. 1169 to 1216.

[10] Attachment 35, Otter Tail's March 2001 Response to EPA's 12/00 Section 114 Information Request, PDF pg. 1172.

[11] Attachment 34, Otter Tail's February 2001 Response to EPA's 12/00 Section 114 Information Request, PDF pg. 12.

[12] *See* Boiler Surface Area Modifications and Mechanical Repair, Technical Specifications 97BSP#18, Jeff Endrizzi, Plant Engineer, June 13, 1997 at 2. Attachment 36, Otter Tail's March 2003 Response to EPA's 12/00 Section 114 Information Request, PDF pg. 490.

[13] July 27, 1995 memo from William J, Swanson, Big Stone Plant Engineer, to Stu

in the boiler resulted in a 5 MW heat rate penalty.[14] Otter Tail's solution to this problem was to add surface area to the primary superheater.[15] [REDACTED]

[16] [REDACTED][17]

Further, by the loss of the protective slag layer that formed from the burning of lignite also damaged the cyclones. This issue with burning subbituminous coal was known to Otter Tail prior to switching to subbituminous coal. Babcock & Wilcox alerted Otter Tail to this issue in 1992 and indicated that "[s]tudding and refractory in cyclones would become a significant annual maintenance project" with the switch to subbituminous coal.[18] Indeed, in the fall of 1998, seven of the 12 cyclones were restudded and refractory was installed.[19]

Scheurs, Engineering Supervisor, entitled "Capital Budget Item - Retrofit of Cyclone Feed Lines." Attachment 35, Otter Tail's March 2001 Response to EPA's 12/00 Section 114 Information Request, PDF pg. 1171.

[14] August 15, 1997 Memo from Stu Schreurs regarding Boiler Modification Cost Justification, Appendix A. Attachment 35, Otter Tail's March 2001 Response to EPA's 12/00 Section 114 Information Request, PDF pg. 15.

[15] Attachment 35, Otter Tail's March 2001 Response to EPA's 12/00 Section 114 Information Request, PDF pg. 12.

[16] [REDACTED]

[17] [REDACTED]

[18] *See* November 9, 1992 letter from Babcock & Wilcox to Otter Tail regarding 1992 inspection of the Big Stone boiler, at 6. Attachment 34, Otter Tail's February 2001 Response to EPA's 12/00 Section 114 Information Request, PDF pg. 2045.

[19] *See* 11/04/98 Big Stone Plant 1998 Overhaul Report-Cyclones. Attachment 36, Otter Tail's March 2003 Response to EPA's 12/00 Section 114 Information Request, PDF pg. 179.

All of these physical changes to the Big Stone boiler had to be made to accommodate the burning of subbituminous coal without derating the power plant and without causing additional damage to the boiler. Thus, for these reasons, the Big Stone facility was not physically capable of accommodating the subbituminous coal.

3. *The Switch from Lignite to Subbituminous Coal Resulted in Significant Emissions Increases for NO_x and PM.*

Otter Tail switched from burning lignite to subbituminous coal in August 1995. Pursuant to the PSD regulations that applied at the time, a "major modification" was defined as:

> [A]ny physical change in or change in the method of operation of a major stationary source that would result in a significant net emissions increase of any pollutant subject to regulation under the Act.

40 C.F.R § 52.21(b)(2)(i) (1995).

"Net emissions increase" is defined as follows:

> [T]he amount by which the sum of the following exceeds zero: (a) [a]ny increase in ***actual emissions*** from a ***particular physical change or change in the method of operation*** at a stationary source; and (b) [a]ny other increases and decreases in ***actual emissions*** at the source that are contemporaneous with the ***particular change*** and are otherwise creditable.

40 C.F.R § 52.21(b)(3)(i)(emphasis added).

The key analysis under this definition is whether the particular "change" will lead to an increase in "actual emissions." This term "actual emissions" has a lengthy definition:

> (i) "Actual emissions" means the actual rate of emissions of a pollutant from an emissions unit, as determined in accordance with paragraphs (b)(21)(ii)- (b)(21)(iv) of this section.
>
> (ii) In general, actual emissions as of a particular date shall equal the average rate, ***in tons per year***, at which the unit actually emitted the pollutant during a two-year period which precedes the particular date and which is ***representative of normal source operation***. The reviewing authority may allow the use of a different time period upon a determination that it is more representative of normal source operation. Actual emissions shall be calculated using the unit's actual operating hours, production rates, and types of materials processed, stored, or combusted during the selected time period.
>
> (iii) The reviewing authority may presume that source-specific allowable emissions for

the unit are equivalent to the actual emissions of the unit.

(iv) ***For any emissions unit which has not begun normal operations on the particular date, actual emissions shall equal the potential to emit of the unit on that date.***

(v) For an electric utility steam generating unit (other than a new unit or the replacement of an existing unit) actual emissions of the unit following the physical or operational change shall equal the representative actual annual emissions of the unit, provided the source owner or operator maintains and submits to the Administrator on an annual basis for a period of 5 years from the date the unit resumes regular operation, information demonstrating that the physical or operational change did not result in an emissions increase. A longer period, not to exceed 10 years, may be required by the Administrator if he determines such a period to be more representative of normal source post-change operations.

40 C.F.R § 52.21(b)(21) (emphasis added).

Big Stone I is an electric utility steam generating unit, but because it never made the reports required under 40 C.F.R. § 52.21(b)(21)(v), that section has no application here. Thus, to determine whether a project triggers PSD applicability, one must compare the facility's annual emissions for the two years preceding the project, 40 C.F.R § 52.21(b)(21)(ii) to the facility's potential to emit after the project. 40 C.F.R § 51.21(b)(21)(iv).

As the attached Excel Spreadsheet, Attachment 3, indicates, on an actual-to-potential basis, the Otter Tail's fuel switch led to a significant emissions increase in NO_x. Actual average annual emissions of NO_x in 1994 and 1995 were 13,008 tons per year. Post project potential emissions for NO_x were 42,140 tons per year, an increase of 29,132 tons per year.[20]

Even if the test set forth in 40 C.F.R § 52.21(b)(21)(v) applies, the fuel switch still caused emissions to increase. To do the calculation required by this subsection, the baseline of 13,008 tons per year would be the same. The subsection, however, calls for a calculation of "representative actual annual emissions," defined in 40 C.F.R § 52.21(b)(33). This section provides that:

(33) Representative actual annual emissions means the average rate, in tons per year, at which the source is projected to emit a pollutant for the two-year period after a physical change or change in the method of operation of a unit, (or a different consecutive two-year period within 10 years after that change, where the Administrator determines that such period is more representative of normal source operations), considering the effect any such change will have on increasing or decreasing the hourly emissions rate

[20] The fuel switch also caused a significant emissions increase in particulate matter. *See* XL Spreadsheet (Emissions Calculation), Attachment 3.

> and on projected capacity utilization. In projecting future emissions the Administrator shall:
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> > (i) Consider all relevant information, including but not limited to, historical operational data, the company's own representations, filings with the State or Federal regulatory authorities, and compliance plans under title IV of the Clean Air Act; and
> >
> > (ii) Exclude, in calculating any increase in emissions that results from the particular physical change or change in the method of operation at an electric utility steam generating unit, that portion of the unit's emissions following the change that could have been accommodated during the representative baseline period and is attributable to an increase in projected capacity utilization at the unit that is unrelated to the particular change, including any increased utilization due to the rate of electricity demand growth for the utility system as a whole.

As Attachment 3 shows, in determining representative actual annual emissions for the fuel switch project, we assumed that demand would not increase at all. Nevertheless, the change in fuel caused the hourly emissions rate for NO_x and PM to increase. Based upon this methodology, representative actual annual emissions for NO_x after the fuel switch were 27,173 tons per year, an increase of 14,165 tons per year.

B. Otter Tail's Modifications to Big Stone to Accommodate Subbituminous Coal Also Constituted a Major Modification

The modifications described above to physically accommodate the combustion of subbituminous coal at Big Stone also added capacity to the boiler to increase the heat input (measured in British Thermal Units or BTUs per hour) and produce more steam (measured in pounds per hour). A boiler designed to burn lignite coal is physically larger than a boiler designed to burn bituminous or subbituminous coal. The physical size of the boiler and the capacity of items such as the coal feed system would allow for more heat input. The design lignite fuel was approximately 6,500 Btu/lb and the subbituminous coal was approximately 9,000 Btu/lb. This means that the boiler was physically capable of feeding 37-44% more heat input into the boiler as a result of the coal switch. However, other components of the boiler were not designed to accommodate this increased heat input. In addition to containing more energy per pound of coal, the subbituminous coal burns hotter and more quickly than the lignite coal. Thus, the change in fuel created a heat imbalance in the boiler, overheating some parts of the superheater and underheating other parts. Accordingly, Otter Tail had to redesign the superheater to avoid overheating and allow for the recovery of capacity discussed above and for increased capacity that could be obtained from the higher heating value of the subbituminous coal. This increase in boiler heat input capacity allowed Big Stone to produce more steam flow.

In 1995, Otter Tail stated to SDDENR that "once the fuel switch is made from lignite to subbituminous coal, we will use fewer tons of coal than are currently used."[21] However, a review of the amount of coal burned until 2001[22] shows that the amount of coal burned increased significantly after the elimination of the pre-dry system in 1996 and after the superheater redesign in 1998. (*See* Big Stone Plant Fuel Burn Record Summaries, Attachment 4. *See also* Attachment 33, Otter Tail's January 2001 Response to EPA's 12/00 Section 114 Information Request, PDF pp. 226-62. Yet, in 1999 through 2001, the amount of coal burned is very similar to the amount of lignite burned annually at Big Stone prior to the switch to subbituminous coal, and the heating value of the subbituminous coal is 37-44% higher than the heating value of the lignite coal (considering both types of subbituminous coal utilized at Big Stone I during 1999-2001).

As with the coal switch, because Otter Tail never made the reports required under 40 C.F.R. § 52.21(b)(21)(v), that section which allows for a comparison of actual to representative actual emissions has no application here. Thus, to determine whether a project triggers PSD applicability, one must compare the facility's annual emissions for the two years preceding the project, 40 C.F.R § 52.21(b)(21)(ii) to the facility's potential to emit after the project. 40 C.F.R § 51.21(b)(21)(iv). As shown in Attachment 3, a comparison of Big Stone I's emissions before the 1998 modifications to its potential emissions after the modifications shows an emissions increase of 9,642 tpy of NOx and 115 tpy of PM. Thus, this modification also triggered PSD applicability as a major modification.

Even if the test set forth in 40 C.F.R § 52.21(b)(21)(v) applies, the fuel switch still caused emissions to increase. As shown in Attachment 3, the 1998 modifications allowed for a derate recovery which was equivalent to an increase in heat input of 2,286,726 MMBtu per year, which would result in a significant emissions increase of NO_x and PM. Thus, the 1998 modifications to Big Stone I should have been permitted as a major modification under the PSD permitting regulations.

C. Otter Tail Modified Big Stone I to Provide Steam to a Colocated Ethanol Plant

On November 28, 2000, Otter Tail requested approval for a minor permit amendment to its Title V permit to supply steam to the Northern Growers Cooperative ethanol plant which would be constructed adjacent to Big Stone I. Attachment 5. Otter Tail claimed that the ethanol plant would be a separate source from the power plant and that the addition of the steam line,

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[21] *See* March 24, 1995 letter from Otter Tail to SDDENR regarding Big Stone Plant Transfer House Dust Collection System. Attachment 34, Otter Tail's February 2001 Response to EPA's 12/00 Section 114 Information Request, PDF pg. 1249.

[22] Because Big Stone I began supplying steam to the Northern Corn Growers Cooperative Ethanol Plant and burning 2-2.5% more coal in 10/02 (as described in the next section of this letter), only data from 2001 and back was reviewed.

condensate return line and associated steam supply is not a major modification pursuant to 40 C.F.R. §52.21(b)(2)(iii)(f) which provides that a "physical change or change in the method of operation shall not include. . .(f) an increase in the hours of operation or in the production rate, unless such change would be prohibited under any federally enforceable permit condition which was established after January 6, 1975, pursuant to 40 CFR 52.21 or under regulations approved pursuant to 40 CFR subpart I or 40 CFR 51.166." Otter Tail claimed it was "not aware of any federally enforceable emissions permit condition that would limit the plant's ability to provide process steam to the ethanol plant." Otter Tail also provided documentation that no significant net emissions increase would occur as a result of the change, using 1999-2000 emissions as baseline emissions and then comparing to its calculation of potential to emit after the modification. Additional emissions information was provided in letters dated January 10, 2001 and April 2, 2001. Attachments 6 and 7.

In its April 2, 2001 letter, Otter Tail pointed out that, while its plans are to provide steam from the cold reheat line after the turbine, steam also must be available from a second location when the steam pressure at the primary location cannot be maintained above acceptable levels. Therefore, steam will likely also be provided from the high pressure steam line ahead of the turbine. Otter Tail further stated "[b]ecause the boiler steam production is turbine-limited, extracting steam ahead of the turbine could theoretically allow for boiler operation, and potential hourly emission rates, in excess of current levels if steam was also extracted from the high pressure steam line for the ethanol plant during historical maximum boiler loads." Otter Tail then indicated that, "to avoid the potential for an emissions increase when extracting steam from the main steam line, the extraction system will include provisions in the control system prohibiting extraction from the main steam line whenever the unit electrical load is above 400 megawatts gross electrical load." This line of reasoning is spurious because extraction of steam from the cold reheat steam line reduces the enthalpy of the steam entering the reheater and, therefore, more heat in the form of coal burned is required to make up for this extracted energy.

On August 8, 2001, SDDENR issued a minor permit amendment to the Big Stone Title V permit. Attachment 29**.** Although the accompanying Statement of Basis, Attachment 30, found that no permit modification was necessary for Otter Tail to provide steam to the ethanol plant, SDDENR none-the-less revised the Big Stone permit to make clear that the steam generator used at Big Stone was not just to produce electricity but also to provide steam to an ethanol plant. By changing the permit language to document this fact, SDDENR acknowledged that a change in method of operation has occurred at Big Stone. Big Stone has changed from a utility generator boiler to a cogeneration facility. SDDENR also increased the permitted maximum heat input capacity to the boiler from 4,509 MMBtu/hr to 5,609 MMBtu/hr. Last, SDDENR replaced the existing 1,226 pound per hour PM limit with a 0.26 lb/MMBtu PM limit

This physical change and change in the method of operation to the Big Stone plant was, in fact, a major modification that should have triggered a PSD review for at least SO_2 and PM. Otter Tail improperly portrayed this change as an increase in production that was achievable under existing limitations. Contrary to Otter Tail's claim, the exemption from the definition of "major modification" for increases in production does not apply here. First, that exemption only applies when there is no other physical change or change in the method of operation accompanying the increase in production. Here, there *was* a physical change to the facility by the physical addition of lines to provide steam from the Big Stone facility to the new ethanol facility, brought from the both the high pressure steam line and the cold reheat line. (See 4/2/01 letter from Otter Tail to SDDENR, Attachment 7). Second, SDDENR documented a change in method of operation at Big Stone by changing the permit language to establish the change from a utility generator boiler to a cogeneration facility. Third, Otter Tail projected that this physical modification and change in method of operation would result in burning 2-2.5% more coal to provide the additional steam to operate the ethanol plant. (See 11/28/00 Otter Tail request for minor permit amendment, Attachment 5). Fourth, as evidenced by the change to Big Stone's Title V operating permit, Big Stone had a change in the method of operation from "a steam generator that is used to produce electricity" to "a steam generator that is used to produce electricity *and provide steam to an ethanol plant*." (*See* Description of Permitted Units, Operations, and Processes of Big Stone Title V permit, as amended on August 8, 2001, emphasis added, Attachment 29). Further, based on Otter Tail's own statements that the facility was turbine-limited at the time of the project (see 4/2/01 letter at 2), the projected increase in production could not have occurred without the physical change and the change in the method of operation. The coal burned (reported to be an estimated 2-2.5%increase) represents an increase in both hourly and annual emissions that should have undergone review for applicability of New Source Performance Standards (NSPS) as well as PSD.

This modification allowed for a significant net emissions increase of SO_2 and PM. Otter Tail's analysis, and SDDENR's review of that analysis, that there could be no significant emissions increase from the changes is seriously flawed. In reviewing this project for applicability to the PSD permitting regulations, Otter Tail chose to use the "actual to potential" test.[23] However, Otter Tail improperly calculated Big Stone's potential emissions. "Potential to emit" is defined as

> the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of a source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed shall be treated as part of its design if the limitation or the effect it would have on emissions in federally enforceable. . . .

40 C.F.R. §52.21(b)(4).

The New Source Review Workshop Manual states that, in determining potential to emit, the worst case uncontrolled emission rate based on the "dirtiest fuels, and/or the highest emitting

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[23]As discussed in June 19, 2001 email from Terry Graumann to Brian Gustafson, Attachment 8.

materials and operating conditions the source is or will be permitted to use under federally-enforceable requirements." (Page A.19 of October 1990 Draft New Source Review Workshop Manual).

Otter Tail's potential to emit calculations do not reflect the maximum operating rate of the Big Stone I steam generator of 5,609 MMBtu/hr, which was increased from 4,560 MMBtu/hr in the August 8, 2001 revised Title V permit and which was also revised to clearly indicate that 5,609 MMBtu/hr is the "maximum operating rate" of the steam generator.[24] Thus, the potential to emit calculations must be based on this maximum operating heat input capacity limit and assuming operation 8,760 hours per year because there are no limits on hours of operation. Otter Tail also assumed a "maximum emission rate" of SO_2 of 0.95 lb/MMBtu. However, there are no enforceable requirements mandating compliance with such an SO_2 emission rate at Big Stone. Thus, the potential to emit SO_2 at Big Stone must be based on worst case SO_2 characteristics of subbituminous coal because there is no enforceable limit on sulfur content of the subbituminous coal to be burned at Big Stone I. For the purposes of our calculation below, we used the SO_2 emission rate reported by Otter Tail as the maximum expected emission rate of 0.95 lb/MMBtu.[25] This emission rate is much less than worst case for subbituminous coal and yet, as shown below, Big Stone I's potential to emit assuming this level of SO_2 emissions would allow a significant emission increase of SO_2. For PM and NO_x, Big Stone's Title V permit includes emission limitations that can be taken into account in calculating potential to emit of these pollutants.

Thus, Big Stone's potential emissions after the modification to provide steam to the ethanol plant are more properly calculated as follows:

NO_x:	5,609 MMBtu/hr x 0.86 lb/MMBtu x 8,760 hrs/year =	17,177 tons per year
SO_2:	5,609 MMBtu/hr x 0.95 lb/MMBtu x 8,760 hrs/year =	23,339 tons per year
PM :	5,609 MMBtu/hr x 0.26 lb/MMBtu x 8,760 hrs/year =	6,388 tons per year

The baseline emissions as provided by Otter Tail based on 1999 - 2000 average annual emissions were[26]:

NO_x: 20,118 tpy

[24] Otter Tail's potential to emit calculation in its June 19, 2001 email to SDDENR relied on the maximum fuel consumption identified in the Title V permit application of 2,270,000 tons per year and the coal heating value (at the time of the Title V permit application) of 8,800 BTU/lb. This equates to the previously listed maximum heat input capacity of 4,560 MMBtu/hr multiplied by 8,760 hours of operation per year.

[25] *See* Enclosure I to June 19, 2001 email from Terry Grauman, Otter Tail, to Brian Gustafson, SDDENR, Attachment 8.

[26] Per Otter Tail's April 2, 2001 submittal to SDDENR, Attachment 7.

SO_2: 19,612 tpy
PM: 367 tpy

Thus, on an actual to potential basis, the ethanol plant project caused an increase in SO_2 emissions 3,727 tpy and an increase in PM emissions of 6,021 tpy, triggering PSD review for those pollutants.

Otter Tail could have used the "WEPCO" approach of comparing baseline actual emissions to representative actual annual emissions of the unit after the change to determine if a modification had occurred, pursuant to 40 C.F.R. §52.21(b)(21(ii)(v) if it would have submitted annual reports for at least five years to show that the change did not result in an emissions increase. However, Otter Tail declined to use this approach - at least for SO_2 and NO_x (see 6/19/01 email from Terry Graumann to Brian Gustafson, SDDENR, Attachment 8).

Thus, the modification at Big Stone to provide steam to the colocated ethanol plant was a major modification that should have been subject to PSD. BACT should have been required at the boiler because this modification, by Otter Tail's own admission, would require an additional 2.5% fuel consumption, equivalent to an additional 59,452 tons of coal burned per year.[27] Even with just assuming actual emission rates, that additional coal would result in a significant emission increase at the boiler of SO_2 and NO_x, as follows:

SO_2: 59,452 tons coal x 8,400 BTU/lb x 0.95 lb/MMBtu = 474 tons per year
NO_x: 59,452 tons coal x 8,400 BTU/lb x 0.84 lb/MMBtu = 419 tons per year

Consequently, Otter Tail cannot use emissions reductions at Unit 1 to offset the emission increases expected from the proposed new unit 2 because the emissions at Big Stone I are illegal.

D. Otter Tail Modified Big Stone I with its 2005 HP-IP Turbine Efficiency Improvement Project

Otter Tail also illegally modified Big Stone I without obtaining the proper PSD permit when it installed a redesigned high pressure and intermediate pressure (HP/IP) steam turbine during its 2005 maintenance outage. Otter Tail described this modification in a May 4, 2004 letter to SDDENR, Attachment 9. Otter Tail claimed this modification was routine maintenance and was exempt under the EPA's Equipment Replacement Rule (68 Fed.Reg. 80186-80289, October 27, 2003). However, that rule has since been struck down by the D.C. Circuit Appeals Court as inconsistent with the Clean Air Act. *(See State of New York, et al., v. Environmental Protection Agency*, No. 03-1380, U.S. Court of Appeals, D.C. Circuit, Decided March 17, 2006). Therefore, any physical change at Big Stone I that could increase emissions must be reviewed as a modification.

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[27] *See* Enclosure I to Otter Tail's June 19, 2001 email to SDDENR.,Attachment 8.

The HP/IP turbine efficiency improvement project is a physical change that could increase emissions at the Big Stone source. Otter Tail provided in its May 4, 2004 letter that the turbine efficiency project will “allow the electrical generator to provide more electrical output per pound of steam.” Otter Tail further states: “The basis for the replacement of the HP/IP turbine steam path section is increased thermal performance resulting in an increase in power output. The project will result in a minimum incremental increase of 5 MW additional power over our existing base conditions, and an increase in cruise rating of 10 MW.” In addition, Otter Tail explained that a “generator upgrade is included as a component of this project” and that “[a]dditional generator capability will be achieved by installing new bushings and new hydrogen coolers.” Also, a “new generator step up transformer will be installed to match the increased generator output.”

Otter Tail claimed that these modifications would not affect the maximum capability of the Unit 1 boiler to burn fuel. However, Otter Tail’s claim directly conflicts with statements previously made by Otter Tail that the boiler’s ability to produce steam is turbine limited (see April 2, 2001 letter regarding providing steam to the colocated ethanol plant, Attachment 7) as well as statements made by SDDENR (“The turbine acts as a bottleneck for the boiler because the boiler is oversized,” Statement of Basis for August 8, 2001 minor permit amendment, Attachment 30). While Otter Tail attempted to clarify its prior statements on the boiler being turbine limited in its May 20, 2004 letter to SDDENR (Attachment 10), it must be noted that Otter Tail never stated that the boiler was *not* turbine limited. And Otter Tail provided no numeric details to show what the capacity of the existing turbine, the existing generator, and the existing step up transformer were compared to steam production capacity of the boiler. Further, even if it wasn’t the turbine that limited steam production (which has not been clearly stated or demonstrated), Otter Tail’s May 4, 2004 letter indicates that the generator and the step up transformer also acted as bottlenecks to increased production. Because the turbine efficiency improvement project allowed for an increase in electrical generation of 10 MW or more (“if boiler cleanliness results in higher reheat temperature”) over Big Stone’s cruise rating, clearly the boiler was debottlenecked as a result of this modification. Low reheat temperature also results from the ethanol project in that the extraction point is, reportedly, the cold reheat line.

In spite of Otter Tail’s claim that the turbine efficiency improvement project was routine maintenance and not a modification that increased capacity, Otter Tail provided an emissions evaluation of its baseline actual emissions and its projected actual emissions in its May 4, 2004 letter. Interestingly, Otter Tail *did* project a future increase in actual emissions. (Table 1 of Attachment 9). However, Otter Tail claimed that all increases in production and emissions would be solely due to product demand growth “and will be completely unrelated to the project.”

Otter Tail cannot simply claim increased emissions are due solely to demand growth and then claim exemption from PSD. In order to exclude future increases in emissions under the “demand growth” exclusion, Otter Tail must adequately demonstrate that the increase in steam production could have been accommodated during the baseline period and that the increase is not related to the physical or operational changes to the facility. (67 Fed.Reg. 80,277, December

31, 2002). It is not enough to simply provide a statement to this effect. Otter Tail needs to prove that it could have accommodated the increase in production during the baseline period (with specific details given to show the maximum steam production capacity of the boiler and that the HP-IP turbine, the generator, and the step up transformer all could have accommodated the increase in production that could be allowed with the HP-IP turbine efficiency project). EPA has also stated that "even if the operations of an emissions unit to meet a particular level of demand could have been accomplished during the representative baseline period, but it can be shown that the increase is related to changes made to the unit, then the emissions increases resulting from the increased operation must be attributed to the modification project, and cannot be subtracted from the projection of post-change actual emissions." (From EPA's Technical Support Document for the Prevention of Significant Deterioration and Nonattainment Area New Source Review Regulations I-3-11 (2002), as quoted in *State of New York, et al., v. U.S. Environmental Protection Agency*, U.S. Court of Appeals, D.C. Circuit, No. 02-1387, decided June 24, 2005 at 51.) For example, by making the turbine more efficient, electricity can be produced at lower costs which would likely increase the demand for Big Stone's power.

Otter Tail did submit some very limited information in its May 20, 2004 letter to SDDENR, Attachment 10, but this information did not provide sufficient details to verify whether Big Stone I could have accommodated the increase in production during the baseline period.

Thus, because there is nothing in the record to verify that Big Stone I was capable of accommodating this increase in production in the baseline period, the increased emissions do not quality for the demand growth exclusion. Otter Tail provided projected actual emissions calculations in its May 4, 2004 submittal to SDDENR (Attachment 9). Comparing Otter Tail's "unadjusted projected actual" emissions (which reflect the projected emissions without excluding emissions due to increased demand growth) to Otter Tail's baseline emissions shows that the turbine efficiency project would allow for a significant emissions increase of SO_2 (with an increase of 268.6 tpy) and NOx (with an increase of 329 tpy). Thus, this modification should have been subject to PSD as a major modification for these pollutants.

Thus, for the reasons discussed in detail above, the emissions at Big Stone I are excess and any reduction in emissions at Big Stone I is not available to Otter Tail to offset the potential emissions increase expected from Unit 2. Therefore, Big Stone II must undergo PSD review including meeting emission limits reflective of BACT for NO_x and SO_2, and SDDENR must also require Otter Tail to undergo PSD review for Big Stone I.

III. SDDENR CANNOT ALLOW BIG STONE II TO AVOID PSD REVIEW FOR SO_2 AND NO_X BY OBTAINING OFFSETS

Putting aside, for the sake of argument, Section I of this letter above, even if Otter Tail had not made major modifications at Big Stone I, reductions at that unit cannot be used to "net out" of PSD review of Big Stone II. According to SDDENR's draft Statement of Basis, "Otter

Tail Power Company's Big Stone II project . . . has made an agreement with Big Stone I owners to reduce its sulfur dioxide and nitrogen oxide emissions to offset the increase in sulfur dioxide and nitrogen oxide emissions from the Big Stone II project." Statement of Basis at 11. SDDENR also stated that Big Stone II will have uncontrolled emissions of several criteria pollutants including SO_2 and NO_x in excess of the 100 ton per year major source threshold, and that "[t]herefore, a single source determination was not conducted." Statement of Basis at 9.

Thus, it appears that SDDENR did not find that Big Stone II and Big Stone I are part of one stationary source, or at the very least, SDDENR believes there is some question whether the two units are part of one stationary source. In any case, the PSD regulations do not allow one new major source to avoid PSD review by obtaining emissions offsets from another major source.

As discussed below, there is a provision in the PSD regulations that calls for determining the net emissions increase from a modification to an existing major stationary source under which decreases in emissions can be considered if creditable and enforceable. However, unless SDDENR definitively determines that Big Stone I and Big Stone II are both part of the same stationary source, such netting of emissions is not allowed. The PSD regulations do not provide for emissions trading between separate sources to avoid PSD.

IV. NOT WITHSTANDING THE ILLEGAL EMISSIONS AT BIG STONE I, BIG STONE II WILL HAVE A SIGNIFICANT EMISSION INCREASE AND A SIGNIFICANT NET EMISSIONS INCREASE OF NO_X AND SO_2

Otter Tail has claimed that, as a result of the requested plantwide cap on actual emissions at Big Stone, there will be no significant actual emissions increase in SO_2 or NO_x from the installation of Big Stone II. (See page ES-2 of Otter Tail's July 2005 PSD Construction Permit Application). SDDENR has claimed that, with the plantwide caps and other proposed emission limits, Big Stone II is not subject to PSD for SO_2 or NO_x because its potential emission increases would be less than the significance rate of 40 tons per year. However, neither Otter Tail or SDDENR has explained whether Big Stone II's emissions would be a major modification under the current PSD regulations, which require both an evaluation of the emission increase from the new unit and an evaluation of net emissions increase at the entire facility. Assuming that Big Stone I was not illegally modified and assuming that SDDENR determines that Big Stone I and II are both part of one major stationary source, Big Stone II must be considered a major modification for NOx and SO_2 as is shown in detail below.

Under the PSD regulations as revised by EPA in 2002, a modification is a major modification if it would cause both a significant emissions increase and a significant net emissions increase. 40 C.F.R. §52.21(a)(2)(iv)(a) (as incorporated into South Dakota's rules at 74:36:09:02). 40 C.F.R. § 52.21(a)(2)(iv)(d) requires that, for construction of a new emissions unit as is the case with Big Stone II, "[a] significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the difference between the potential to emit [as defined in 40 C.F.R. §52.21(b)(4)] *from each new emissions unit* following completion of the project and the baseline actual emissions [as defined in 40 C.F.R. §52.21(b)(48)(iii) *of these units* before the project equals or exceeds the significant amount for that pollutant. . . ." [Emphasis added.] 40 C.F.R. §52.21(b)(48)(iii) provides that "*[f]or a new emissions unit*, the baseline actual emissions for purposes of determining the emissions increase that will result from the initial construction and operation *of such unit* shall equal zero. . . ." [Emphasis added.] Thus, in accordance with these provisions, to determine if a significant emissions increase of SO_2 or NO_x is projected to occur as result of the new Big Stone II unit, the potential to emit of the new unit must be determined and compared to the significant levels for SO_2 and NO_x. The potential to emit of the new unit is based on the maximum capacity of the new unit to emit a pollutant, considering any federally enforceable limitations on that unit.

The only unit-specific limits in the proposed permit are the NSPS limits of 1.4 lb SO_2/MWh (gross) and the 1.0 lb NO_x/MWh (gross). *See* condition 5.1 of the proposed permit. Emissions due to startups, shutdowns and malfunctions are not subject to these emission limits. While the gross MW size of the new unit was not given in Otter Tail's permit application for Big Stone II, the net MW output of a nominal 600 MW was provided. Although this will be an underestimate of potential to emit because it reflects net output, the 600 MW net size of the new unit can be used to calculate potential emissions:

1.4 lb SO_2/MWh x 600MW x 8760 hours of operation/year x 1 ton/2000 lb = 3,679.2 tpy SO_2

1.0 lb NO_x/MWh x 600MW x 8760 hours of operation/year x (1 ton/2000 lb) = 2,628 tpy NO_x

Thus, based on the unit-specific emission limits in the proposed permit, Big Stone II will have a significant emission increase of SO_2 and NO_x (i.e., greater than 40 tpy per the definition of "significant" at 40 C.F.R. §52.21(b)(23)(i)).[28]

The proposed plantwide caps do not specifically limit the potential to emit of Big Stone II to less than significant levels. At best, the plantwide caps could be construed to limit potential to emit of the new units to no more than 13, 178 tons per year SO_2 and 16, 448 tons of NO_x per year. Thus, the plantwide limits will not limit Big Stone II's potential to emit to below PSD significance levels. Big Stone II will produce a significant emissions increase of NO_x and SO_2, contrary to SDDDENR's and Otter Tail's statements.

[28] SDDENR also shows in its Statement of Basis, Attachment 37, that the potential uncontrolled emissions of the boiler at Big Stone II are greater than significant levels for NO_x and SO_2 (*see* page 3 of the SDDENR Statement of Basis, Attachment 37, indicating potential uncontrolled emissions of NO_x at Big Stone II as 11,988 tpy and potential uncontrolled emissions of SO_2 at Big Stone II as 56,700 tpy).

To determine if a significant net emissions increase would occur, the first step in calculating net emissions increase is to determine the increase in emissions from a particular physical change as specified in 40 C.F.R. 52.21 (a)(2)(iv). As discussed in the above, section, the increase in SO_2 and NO_x emissions from Big Stone II, to be based on the potential to emit of the new unit, is greater than the PSD significance levels for SO_2 and NO_x.

To calculate net emissions increase at the Big Stone facility, one must add and subtract all contemporaneous and creditable increases and decreases in emissions at the facility. The procedures for this calculation are spelled out in EPA's October 1990 New Source Review Workshop Manual. (Pages A.44 to A.49). It is important to note that Otter Tail's and SDDENR's plantwide cap approach to attempt to exempt the new Big Stone II unit from PSD review for SO_2 and NO_x is flawed with many of the common errors listed by EPA in the New Source Review Workshop Manual that it often encounters in netting determinations, including "using prospective (proposed) unrelated emissions decreases to counterbalance proposed emission increases without also examining all previous contemporaneous emissions changes," "not properly documenting all contemporaneous emissions changes," and "not ensuring that emissions decreases are covered by federally enforceable restrictions, which is a requirement for enforceability." (Workshop Manual at A.44).

The first step in the net emissions increase review is to determine the contemporaneous timeframe, which starts 5 years from the date construction on the modification commences and ends on the date the emissions increase from the new unit occurs. Thus, for the addition of Big Stone II, the contemporaneous period begins in the Spring of 2002 (because on-site construction is projected to begin Spring of 2007, Otter Tail PSD Permit Application at 1-1). Commercial operation is scheduled for Spring 2011 (*Id.*). Thus the contemporaneous period spans from Spring 2002 to Spring 2011.

The second step in the net emissions increase process is to determine which emission units at the source have experienced an increase or decrease in emissions during the contemporaneous period. This would include physical changes or changes in the method of operation that did not require a PSD permit. The Big Stone I unit experienced at least two such increases in emissions between now and Spring 2002.[29] First, the Big Stone I unit began supplying steam to the co-located Northern Lights ethanol plant in October 2002. This was due to both a physical change and change in the method of operation as discussed above in Section I.C.of this comment letter. Second, the Big Stone I unit was debottlenecked to allow an increase in production via the HP-IP Turbine Efficiency Project and associated generator and step-up transformer upgrades, as discussed in Section I.D. of this comment letter. The other potential

[29] Note that for the purposes of this discussion, we are not considering the previous changes to Big Stone I as illegal modifications. As discussed above, netting with emission reductions is not even an option at Big Stone I because the Big Stone I unit was illegally modified and its allowable emissions are thus zero.

change in emissions that could be considered are the planned decrease in emissions at Big Stone I via the routing of Big Stone I emissions through the wet scrubber planned for Big Stone II and the "more aggressive" use of the Big Stone I low NO_x burners. (Otter Tail PSD Permit Application at ES-2).

The third step is to determine which emission increases and decreases are creditable. The criteria for determining if a change in emissions is creditable include:

a) The reviewing authority must not have relied on the emission increase or decrease in a previously issued PSD permit.

b) A decrease is only creditable to the extent that it is federally enforceable from the moment actual construction begins on the proposed modification. (Note that this requirement for federal enforceability was subsequently changed to a requirement that the decrease be enforceable as a practical matter at and after the time construction on the particular change begins. See 40 C.F.R. §52.21(b)(3)(vi)(b).) The decrease must occur before the proposed emission increase occurs.

c) A source cannot take credit for a decrease that it has to make, or will make, to bring a unit into compliance.

(See pages A.47 to A. 48 of New Source Review Workshop Manual).

As discussed above, Big Stone I is in violation of PSD and thus Otter Tail cannot take credit for any decrease in emissions it has to make to bring Big Stone I into compliance. But for the purposes of this specific comment, we are ignoring this issue.

According to the definition of "net emissions increase" at 40 C.F.R. §52.21(b)(3), "baseline actual emissions" for the purposes of determining creditable increases and decreases are to be determined in accordance with 40 C.F.R. §52.21(b)(48) except that §52.21(b)(48)(i)(c) and (ii)(d) don't apply. Otter Tail did not select a level of "baseline actual emissions" because it did not conduct a netting analysis. For the purposes of this analysis, we will assume that Otter Tail would select 2003-2004 as the Big Stone I baseline actual emissions period, since this was the period of emissions used for its proposal of its NO_x and SO_2 plantwide emissions cap. Thus, Big Stone I's baseline actual emissions are 13,278 tons per year (tpy) SO_2 and 16,448 tpy NO_x. (See page 3-2 of Otter Tail's PSD permit application).

Because the baseline actual emissions period is after the modification to Big Stone I to provide steam to the ethanol plant, no increase in emissions due to that modification would be creditable. See 40 C.F.R. §52.21(b)(3)(v). However, the increase in emissions due to the HP-IP Turbine Efficiency project including generator and step-up transformer upgrade project would be creditable, because it occurred in 2005 after the baseline actual emissions period. The level of emissions increase that is creditable from this change is the difference between the Big Stone I emission unit's "actual emissions" as defined in 40 C.F.R. §52.21(b)(21) after the change and the unit's "baseline actual emissions" before the change. As discussed in the New Source Review Workshop Manual, the new level of emissions is the lower of the emission unit's allowable emissions or potential to emit. It is important to note that this determination of creditable increases as well as decreases is based on changes at each emissions unit. *See* definition of "actual emissions" at 40 C.F.R. §52.21(b)(21) which is defined as the actual rate of emissions. . . *from an emissions unit*. Similarly, the definition of "baseline actual emissions" is also based on the emissions rate at an emissions unit. See 40 C.F.R. §52.21(b)(48).

Thus, the "new level of actual emissions" of NO_x at Big Stone I after the HP-IP Turbine project is the unit's allowable emissions, which are based on the unit's maximum heat input capacity and allowable NO_x emission limit as follows[30]:

5,609 MMBtu/hr x 0.86 lb/MMBtu x 8,760 hrs/year = 17,177 tons per year

For SO_2, there are no allowable emission limits. However, for the purpose of this calculation, we will use Otter Tail's statement maximum expected SO_2 emission rate of 0.95 lb/MMBtu (see Attachment 8). Thus the "new level of actual emissions" of SO_2 after the turbine project are:

5,609 MMBtu/hr x 0.95 lb/MMBtu x 8,760 hrs/year = 23,339 tons per year

Thus, the creditable increase from this change is:

SO_2: 23,339 tpy - 13,278 tpy = 10,061 tpy
NO_x: 17,177 tpy - 16,448 tpy = 729 tpy.

We must next evaluate the planned decrease in SO_2 and NO_x emissions at the Big Stone I unit due to the planned routing of Big Stone I emissions through the wet scrubber planned for Big Stone II and the "more aggressive" use of the Big Stone I low NO_x burners. To determine the amount that is creditable, the new level of actual emissions must be less than the old level of baseline actual emissions. 40 C.F.R. §52.21(b)(3)(vi)(a). Again, as discussed above, the definitions of "actual emissions" and "baseline actual emissions" are based on "the actual rate of emissions. . . *from an emissions unit*." In addition, for a decrease in actual emissions to be creditable, it must be enforceable as a practical matter. 40 C.F.R. §52.21(b)(3)(vi)(b).

As stated above, the baseline actual emissions at the Big Stone I unit are assumed to be 13,278 tons per year (tpy) SO_2 and 16,448 tpy NO_x. The actual emissions after the changes of routing the Big Stone I emissions through the wet scrubber and of operating the low NO_x burners more aggressively must be based on the lower of allowable emissions or potential to emit *of the unit*. See 40 C.F.R. §52.21(b)(21)(iii) and (iv). The proposed plantwide caps for NO_x and SO_2 do not limit emissions from the Big Stone I unit. At best, one could interpret the plantwide caps

[30] Note that the definition of "projected actual emissions" including the demand growth exclusion does not apply in determining the emissions increase from the HP-IP Turbine project (including generator and step-up transformer upgrades) in a netting analysis.

as limiting emissions from Big Stone I to 13,278 tpy of SO_2 and 16,448 tpy of NO_x, in which case there are no emission reductions below baseline actual emissions that can be credited.

There are no other proposed emission limits to ensure practical enforceability of any level of emission reductions at Big Stone I. While SDDENR has proposed a provision that would require Otter Tail to route the emissions from Big Stone I through the wet flue gas desulfurization system for Big Stone II "on or after" the initial startup of Big Stone II (see proposed permit condition 5.10), this provision does not ensure the practical enforceability of SO_2 emission reductions at Big Stone I because it does not specify any level of SO_2 reduction that must be achieved at Big Stone I or any unit-specific emission limit. Further, it does not require that such routing of emissions occur before startup of Big Stone II. There are also no other requirements in the proposed permit that would effectively limit NO_x emissions from Big Stone I.

Thus, the planned reductions in emissions at Big Stone I are not creditable in the determination of net emissions increase.

The last step in the netting process is to sum all of the creditable emissions increases and decreases to determine if a net emissions increase will occur. For Big Stone, the net emissions increase is as follows:

Potential to emit from the new Big Stone II unit:

3,679 tpy SO_2
2,628 tpy NO_x (See Section III. above for these calculations)

Creditable increases:
HP-IP Turbine retrofit project:
10,061 tpy SO_2
729 tpy NO_x

Creditable decrease:
0 tpy SO_2
0 tpy NO_x

Net emissions increase of SO_2:
3679 tpy + 10,061 tpy - 0 = 13,740 tpy SO_2

Net emissions increase of NO_x:
2628 tpy + 729 tpy - 0 = 3,357 tpy NO_x

Thus, notwithstanding the illegal modifications at Big Stone I and assuming that SDDENR finds that Big Stone I and Big Stone II are one source, then there would be a significant net emissions increase of SO_2 and NO_x at the Big Stone facility.

Consequently, the modification at Big Stone would have both a significant emissions increase in SO_2 and NO_x (as discussed in Section III. above) and a significant net emissions of SO_2 and NO_x. Thus, Otter Tail must meet PSD requirements including BACT for NO_x and SO_2 emissions for the Big Stone II modification.

V. NOTWITHSTANDING THE ILLEGAL EMISSIONS AT BIG STONE I, THE PROPOSED PLANTWIDE LIMIT DOES NOT COMPORT WITH THE PLANTWIDE APPLICABILITY LIMIT PROVISIONS OF THE PSD REGULATIONS

As discussed in detail above, the proposed plantwide caps on SO_2 and NOx emissions will not ensure that Big Stone II will not result in a significant emissions increase and a significant net emissions increase of NOx and SO2. The only other approach that is allowed under the PSD regulations to exempt a new unit from PSD applicability is under the plantwide applicability limit (PAL) provisions of the PSD regulations at 40 C.F.R. §52.21(aa). However, the proposed plantwide caps also do not comport with the PAL provisions of the PSD regulations, nor does SDDENR claim to be relying on those provisions as providing legal authority to justify the proposed plantwide emissons cap to net the new Big Stone unit out of review for SO2 and NOx.

Specifically, while the PAL provisions do allow an existing source to construct a new unit without triggering PSD if total plantwide emissions stay under the level of the PAL (40 C.F.R. §52.21(aa)(1)(ii)), the PAL provisions do not allow for establishment of a PAL concurrent with the proposed addition of a new unit. Indeed, in setting the limit of the PAL, the facility is to add the potential to emit of the new units to the baseline actual emissions of the existing units. 40 C.F.R. §52.21(aa)(6)(ii). If Otter Tail were to do that, the total emission level of the PAL would allow for significant emissions increases as compared to baseline actual emissions and thus the new unit would be subject to PSD.

Further, there are many other requirements to establish a PAL which SDDENR has not addressed. See 40 C.F.R. §52.21(aa)(4), (7), and (12)-(14)

Thus, for all of the above reasons including that a PAL cannot be set up concurrently with the proposed addition of a new unit without triggering PSD, the proposed plantwide cap at Big Stone does not comport with the only provisions in the PSD regulations that would allow for a plantwide cap on emissions to exempt a new unit from PSD review (i.e., the PAL provisions at 40 C.F.R. §52.21(aa)).

VI. NOT WITHSTANDING ALL OF THE ABOVE COMMENTS, SDDENR DID NOT

ANALYZE WHETHER BIG STONE COULD COMPLY WITH THE PROPOSED EMISSION CAPS

Not withstanding all of the above issues that would not allow Otter Tail to legally use plantwide caps on SO_2 and NOx to avoid PSD review for Big Stone II, SDDENR did not even evaluate whether the proposed emission caps could be readily met at Big Stone. Further, Otter Tail did not provide sufficient data to verify how it would meet these emission caps. For example, Otter Tail failed to provide any data on the characteristics of the coal to be burned at Big Stone II. Without such data, SDDENR does not know the uncontrolled SO_2 emission rate and thus cannot determine the level of SO_2 control that will need to be met at the proposed SO_2 scrubber at Big Stone. Otter Tail also provided no details on the planned operation, including expected control efficiency, of the wet scrubber. Further, Otter Tail provided no details on how the NO_x emission cap would be met except to state that the low NO_x burners at Big Stone I would be "more aggressively" operated, a meaningless claim without supporting details. Thus, even if it was legitimate to exempt Big Stone II from PSD review for NO_x and SO_2 based on the proposed plantwide caps (which, for the numerous reasons described above, we believe are not legally supported), SDDENR cannot simply impose these plantwide caps without requiring sufficient documentation to be submitted as part of the permit record and a meaningful review conducted to verify that these plantwide caps can indeed be met at Big Stone. It appears the state will simply "take it on faith" that these emission caps will be met. Thus, SDDENR could potentially allow for significant violations of Clean Air Act PSD permitting requirements without providing sufficient documentation in the public record to show that the emission caps can be complied with and that the exemptions are warranted.

VII. NOT WITHSTANDING ALL OF THE ABOVE COMMENTS, SDDENR DOES NOT HAVE LEGAL AUTHORITY FOR IMPOSING PLANTWIDE EMISSION CAPS AND EXEMPTING BIG STONE II FROM PSD IN THE PROPOSED PSD PERMIT

Not withstanding all of the above issues that would not allow Otter Tail to legally use plantwide caps on SO_2 and NOx to avoid PSD review for Big Stone II, SDDENR did not explain its legal authority for creating plantwide caps and exempting Big Stone II from PSD review for SO_2 and NOx. As discussed above, we find that SDDENR does not have such legal authority because the emissions from Big Stone I are illegal and because, under the PSD regulations, Big Stone II would be a major modification for SO_2 and NOx because it would have a significant emission increase and a significant net emission increase of these pollutants. In addition to these major issues, SDDENR does not have authority to impose plantwide caps on SO_2 and NOx in a construction permit. South Dakota's PSD regulations (ARSD 74:36:09), which incorporate by reference the federal PSD regulations, do not provide for imposition of emission limits to avoid PSD review. Further, South Dakota's minor source construction and operating permit program (ARSD 74:36:04) does not provide for imposition of emission limits to avoid PSD review, because that program only applies to minor sources and Big Stone is a major stationary source. Indeed, South Dakota's minor source construction and operating permit program does not even provide authority to issue emission limits on Big Stone I alone. Thus, if SDDENR wanted to limit the potential to emit on Big Stone I, it would have to do so through a source-specific SIP revision. In any event, SDDENR does not have legal authority to support its proposed plantwide caps on SO_2 and NOx emissions at Big Stone.

VIII. NOT WITHSTANDING ALL OF THE ABOVE ISSUES, THE DRAFT AIR QUALITY PERMIT FAILS TO SPECIFY ADEQUATE COMPLIANCE PROVISIONS FOR THE PLANTWIDE CAPS

Not withstanding all of the above illegalities with the plantwide caps on NOx and SO_2 at Big Stone, Big Stone II cannot avoid PSD review for SO_2 and NO_x because the plantwide caps as proposed in the draft permit lack compliance provisions to ensure enforceability. In its Statement of Basis for the draft permit, SDDENR stated that, for the plantwide caps to be enforceable as a practical matter, the limitations "must be written so that it is possible to verify compliance and to document violations when enforcement action is necessary. The limitations should be permanent, contain a legal obligation for the source to adhere to the terms and conditions, be technically accurate and quantifiable, identify an averaging time that allows at least monthly checks, and require a level of recordkeeping, reporting, and monitoring sufficient to demonstrate compliance with the limit." Statement of Basis at 13. Yet, the proposed plantwide caps in the draft permit do not meet any of these criteria. The plantwide caps apply to the Big Stone I and II boilers, the fire pump and generator for Big Stone II, and Units #2, 3 and 4 at Big Stone I. While the draft permit indicates that the SO_2 and NO_x emissions monitored by the continuous emission monitoring systems (CEMS) at the Big Stone I and II boilers "shall be used in the plantwide limit compliance demonstration." Conditions 5.6 and 5.8 of the draft permit. No more detail is specified in the permit as to how Otter Tail is to show compliance with the plantwide caps. In order for the plantwide caps to be enforceable, there must be specific provisions in the permit on what recordkeeping must be done, how emissions from the various units are to be determined and summed to show compliance with the cap and over what timeframe, how to deal with missing CEMs data due to monitor downtime, and these provisions must ensure that the sum of emissions from the entire Big Stone facility is technically accurate.

Also, it is not clear how emissions from Big Stone I will be monitored during the times its flue gas is not being routed to the wet scrubber. It is also not clear whether any partial bypass of the scrubber will be allowed. The permit needs to make clear that CEMS at Big Stone I must be used at all times, in addition to the CEMS at Big Stone II, to show compliance with the plantwide cap.

Further, to ensure technical accuracy, SDDENR must require more frequent testing than just an initial stack test of Units 2, 3, 4, 14, and 15. In addition, the draft permit does not specify *any* stack testing of these units for SO_2 emission rates, and yet all of these units are subject to the SO_2 plantwide cap. The draft permit also lacks sufficient criteria for the testing to ensure that worst case emission rates are determined.

The draft permit also lacks adequate reporting requirements for SDDENR to conduct monthly checks of Big Stone's compliance with the plantwide caps. The draft permit only requires quarterly reporting, and this reporting will only be required until the permit #28.0801-29 has been revised. Condition 3.6 of the draft permit. With only quarterly reports not submitted until 30 days after the end of a quarter, SDDENR may not know about a violation until 4 months after it occurred. Further, the reporting requirement in Condition 3.6 lacks sufficient detail to ensure technical accuracy in the emissions totals to be provided by Otter Tail.

The draft permit also is unclear on the repercussions for a violation of the plantwide cap. Section 1.4 must make clear that a violation of a rolling monthly plantwide cap could be subject to a penalty of $10,000 per day for each day of the month the source is in violation. More importantly, this section of the permit must make clear that, if Big Stone's rolling 12-month tally of SO_2 or NO_x emissions exceeds the plantwide SO_2 or NO_x caps, then Big Stone II must meet PSD requirements for those pollutants as though construction had not yet commenced.

Also, the language in Conditions 5.6 and 5.8 is vague in stating that any relaxation "in the permit" that increases "applicable emissions" equal to or greater than the cap shall trigger a full PSD review. Instead of using confusing terms, the permit should just clearly state that any relaxation in this plantwide cap would subject Big Stone II to PSD permitting as though construction had not yet commenced. 40 C.F.R. §52.21(r)(4).

For all of the above reasons, the plantwide caps proposed by SDDENR are not enforceable as a practical matter, and thus - even if Big Stone II could legitimately avoid PSD review for SO_2 and NO_x via plantwide caps - the plantwide caps are not sufficient to exempt Big Stone II from PSD for SO_2 and NO_x.

IX. SDDENR DID NOT VERIFY THAT THE EMISSION REDUCTIONS AT BIG STONE I WILL HAVE THE SAME QUALITATIVE SIGNIFICANCE AS THE EMISSION INCREASES AT BIG STONE II

For all of the reasons discussed above, Big Stone II cannot be legitimately exempt from PSD review for SO_2 and NO_x. Notwithstanding those issues, SDDENR cannot allow Big Stone II to avoid PSD review without an analysis that the emission reductions at Big Stone I have the same qualitative significance for public health and welfare as the emission increases at Big Stone II. See 40 C.F.R. §52.21(b)(3)(vi)(c). This analysis must take into account the dispersion characteristics of Big Stone I as compared to the dispersion characteristics of Big Stone II, which will differ due to size of the units, the unit locations, a more saturated plume on Big Stone II, etc. Without such an analysis, there are no assurances that this requirement for exempting Big Stone II from PSD review for SO_2 and NO_x has been met.

X. THE DRAFT AIR QUALITY PERMIT DOES NOT ADDRESS CARBON DIOXIDE AND OTHER GREENHOUSE GAS EMISSIONS

The draft permit for the Big Stone II did not address carbon dioxide (CO_2) or other greenhouse gases to be emitted from the proposed power plant. However, such emissions can be quite significant from coal-fired boilers. Big Stone II has a potential to emit approximately 8 million tons of carbon dioxide each year.[31]

We believe that the EPA, and the State of South Dakota have a legal obligation to regulate CO_2 and other greenhouse gases as pollutants under the Clean Air Act. Indeed, twelve states, fourteen environmental groups and two cities have filed suit in federal court stating that EPA must regulate greenhouse gas emissions under the Clean Air Act.[32] Specifically, the parties appealed the U.S. EPA's decision to reject a petition that sought to have the federal government regulate greenhouse gas emissions from new motor vehicles. If the federal court agrees that greenhouse gases, such as CO_2, must be regulated under the Clean Air Act, such a decision would also require the establishment of CO_2 emission limits in this permit for Big Stone II.

At the minimum, SDDENR must consider emissions of CO_2 in its BACT analysis for Big Stone II. The federal Environmental Appeals Board (EAB) has interpreted the definition of BACT as requiring consideration of unregulated pollutants in setting emission limits and other terms of a permit, since a BACT determination is to take into account environmental impacts.[33] A recently issued paper entitled Considering Alternatives: The Case for Limiting CO_2 Emissions from New Power Plants through New Source Review by Gregory B. Foote (Attachment 11) discusses the regulatory background to support consideration of CO_2 impacts when permitting a new source and, in particular, a new coal-fired power plant. This paper indicates that it is entirely appropriate to consider CO_2 emissions when evaluating environmental impacts under the new source review permit program, and the paper also suggested approaches for evaluating technologies in terms of CO_2 emissions. This paper and all other documents cited herein are incorporated by reference as part of our comments.

XI. SDDENR FAILED TO EVALUATE IGCC IN THE BACT ANALYSIS

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[31] CO_2 emissions were calculated based on the design rate of the coal conveying system of 380 tons per hour and the EPA AP-42 emission factor for CO_2 from subbituminous coal combustion.

[32] *Commonwealth of Massachusetts, et al. v. U.S. EPA*, No. 03-1361 (Consolidated with Nos. 03-1362-1368) U.S. Court of Appeals for the District of Columbia Circuit.

[33] *See In Re North County Resource Recovery Associates*, 2 E.A.D. 229, 230 (Adm'r 1986), 1986 EPA App. LEXIS 14.

SDDENR's Statement of Basis explains that the state did not require evaluation of IGCC as BACT because consideration of IGCC is redefining the source and that is not required under the New Source Review Workshop Manual. The state also cited to a determination made by EPA on December 13, 2005 that IGCC did not need to be reviewed as BACT for a pulverized coal boiler. It is important to note that this determination made by EPA has been challenged and that challenge has not yet been resolved. *NRDC v. EPA*, D.C. Circuit, No. 06-1059.

The state's determination is wrong, as was EPA's December 2005 determination. BACT by its Clean Air Act definition requires consideration of inherently lower emitting processes.

Integrated Gasification Combined Cycle (IGCC) is an available, demonstrated cleaner coal combustion technology with significant emission reduction benefits. There are numerous benefits to IGCC, including fewer emissions of criteria and hazardous air pollutants, the opportunity for capturing greenhouse gases, such as CO_2, that cause global warming, and a general increase in efficiency over other coal burning technologies.

South Dakota and Federal Law Require a Thorough Evaluation of IGCC as Part of the BACT Analysis.

Section 165(a)(4) of the Clean Air Act (CAA) provides that "no major emitting facility on which construction is commenced after August 7, 1977, may be constructed in any area to which this part applies unless… the facility is subject to the best available control technology for each pollutant subject to regulation under this chapter emitted from, or which results from, such facility." The requirement for conducting a BACT analysis is codified at 40 CFR § 52.21(j).

> BACT is then defined under the federal regulations as follows:
> an emissions limitation (including a visible emissions standard) based on the maximum degree of reduction for each pollutant subject to regulation under [the Clean Air] Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case by case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant.

40 C.F.R. §52.21(b)(12).

This definition includes coal gasification. The legislative history of the amendment adding the term "innovative fuel combustion techniques" to the Clean Air Act's definition of "BACT" is clear. Coal gasification must be considered. The relevant passage of the debate is excerpted below:

> Mr. HUDDLESTON. Mr. President, the proposed provisions for application of best available control technology to all new major emission sources, although having the admirable intent of achieving consistently clean air through the required use of best controls, if not properly interpreted may deter the use of some of the most effective pollution controls. The definition in the committee bill of best available control technology indicates a consideration for various control strategies by including the phrase "through application of production processes and available methods systems, and techniques, including fuel cleaning or treatment." And I believe it is likely that the concept of BACT is intended to include such technologies as low Btu gasification and fluidized bed combustion. But, this intention is not explicitly spelled out, and I am concerned that without clarification, the possibility of misinterpretation would remain. It is the purpose of this amendment to leave no doubt that in determining best available control technology, all actions taken by the fuel user are to be taken into account--be they the purchasing or production of fuels which may have been cleaned or up-graded through chemical treatment, gasification, or liquefaction; use of combustion systems such as fluidized bed combustion which specifically reduce emissions and/or the post-combustion treatment of emissions with cleanup equipment like stack scrubbers. The purpose, as I say, is just to be more explicit, to make sure there is no chance of misinterpretation. Mr. President, I believe again that this amendment has been checked by the managers of the bill and that they are inclined to support it.
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> Mr. MUSKIE. Mr. President, I have also discussed this amendment with the distinguished Senator from Kentucky. I think it has been worked out in a form I can accept. I am happy to do so. I am willing to yield back the remainder of my time.[34]

EPA and federal courts have consistently interpreted the BACT provisions found in the CAA and the agency's regulations as embodying certain core criteria that require the permit applicant either to implement the most effective available means for minimizing air pollution or justify its selection of less effective means on grounds consistent with the purposes of the Act. In Citizens for *Clean Air v. EPA*[35], the Ninth Circuit held that "initially the burden rests with the PSD applicant to identify the best available control." As stated in long-standing EPA guidance, "<u>[r]egardless of the specific methodology used for determining BACT, be it 'top-down,' 'bottom-up,' or otherwise, the same core criteria apply to any BACT analysis: the applicant must consider all available alternatives, and [either select the most stringent of them or] demonstrate</u>

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[34] 95th Congress, 1st Session (Part 1 of 2) June 10, 1977 Clean Air Act Amendments of 1977 A&P 123 Cong. Record S9421.

[35] 959 F.2d 839, 845 (9th Cir. 1992).

why the most stringent should not be adopted."[36] Accordingly, the PSD permit applicant not only must identify all available technologies, including the most stringent, but it must also provide adequate justification for dismissing any available technologies.

Consistent with these core criteria, the EPA's New Source Review (NSR) Workshop Manual establishes that, as the first step in the "top-down" BACT analysis, the applicant must consider all "available" control options:

> The first step in a "top-down" analysis is to identify, for the emissions unit in question (the term "emissions unit" should be read to mean emissions unit, process or activity), all "available" control options. Available control options are those air pollution control technologies or techniques with a practical potential for application to the emissions unit and the regulated pollutant under evaluation. Air pollution control technologies and techniques include the application of production process or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of the affected pollutant. This includes technologies employed outside of the United States. As discussed later, in some circumstances inherently lower-polluting processes are appropriate for consideration as available control alternatives.[37]

"The term 'available' is used…to refer to whether the technology 'can be obtained by the applicant through commercial channels or is otherwise available within the common sense meaning of the term.'"[38] In keeping with the stringent nature of the BACT requirement, EPA has repeatedly emphasized that "available"

> is used in the broadest sense under the first step and refers to control options with a "practical potential for application to the emissions unit" under evaluation. . . . The goal of this step is to develop a comprehensive list of control options.[39]

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[36] Memorandum from John Calcagni, Director of EPA Air Quality Management Division, to EPA Regional Air Directors (June 13, 1989), at 4 (emphasis added).

[37] NSR Manual, at p. B.5 (emphasis added).

[38] *In re: Maui Electric Company*, PSD Appeal No. 98-2 (EAB September 10, 1998), at 29-30 (quoting NSR Manual at B.17).

[39] *In re: Knauf Fiber Glass*, PSD Appeal Nos. 98-3 - 98-20 (EAB February 4, 1999), at 12-13 (quoting NSR Manual at B.5) (emphasis added by EAB); *see also In re: Steel Dynamics, Inc.*, PSD Appeal Nos. 99-4 and 99-5 (EAB June 22, 2000), at 29 n.24 (citing *Knauf* with approval); NSR Manual at B.10 ("The objective in step 1 is to identify all control options with potential application to the source and pollutant under evaluation."); id. at B.6 (emphasizing that

EPA adjudicatory decisions also examine the core requirements for the BACT determination process. "Under the top-down methodology, applicants must apply the best available control technology unless they can demonstrate that the technology is technically or economically infeasible. The top-down approach places the burden of proof on the *applicant* to justify why the proposed source is unable to apply the best technology available."[40]

Whatever analytical process is utilized for determining BACT, these core criteria - the requirement to consider all available technologies, including the most stringent, and to provide adequate justification in the administrative record for dismissing any of the technologies based on relevant statutory factors - must be satisfied.

Thus, to conduct a BACT analysis consistent with the requirements of state and federal law for Big Stone II, SDDENR must thoroughly evaluate all available control measures. IGCC is commercially available today. South Dakota and federal law therefore require that this technology be thoroughly evaluated as part of the Big Stone II BACT analysis.

<u>Recent State Actions Requiring Consideration of Cleaner Coal Technology Establish Irrefutable Precedence for the Consideration of IGCC</u>.

In March 2003, the State of Illinois required the applicant for a proposed CFB coal-fired electric generation facility to conduct a robust analysis of IGCC as a core element of its BACT analysis:

> Additional material must be provided in the BACT demonstration to address Integrated Gasification Coal Combustion (IGCC) as it is a `production process' that can be used to produce electricity from coal. In this regard, the Illinois EPA has determined that IGCC qualifies as an alternative emission control technique that must be addressed in the BACT demonstration for the proposed plant. In addition, based on the various demonstration projects that have been completed for IGCC, the Illinois EPA believes that IGCC constitutes a technically feasible

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a proper Step 1 list is "comprehensive").

[40] *In re: Spokane Regional Waste-to-Energy Applicant*, PSD Appeal No. 88-12 (EPA June 9, 1989), at 9) (internal quotation marks omitted) (emphasis in original); *see also In re: Inter-Power of New York, Inc*., PSD Appeal Nos. 92-8 and 92-9 (EAB March 16, 1994) ("Under the 'top-down' approach, permit applicants must apply the most stringent control alternative, unless the applicant can demonstrate that the alternative is not technically or economically achievable."); *In the Matter of Pennsauken County, New Jersey Resource Recovery Facility*, PSD Appeal No. 88-8 (EAB November 10, 1988) ("Thus, the 'top-down' approach shifts the burden of proof to the applicant to justify why the proposed source is unable to apply the best technology available.")

> production process.
>
> Accordingly, Indeck must provide detailed information addressing the emission performance levels of IGCC, in terms of expected emissions rates and possible emission reductions, and the economic, environmental and/or energy impacts that would accompany application of IGCC to the proposed plant. This information must be accompanied by copies of relevant documents that are the basis of or otherwise substantiate the facts, statements and representations about IGCC provided by Indeck. In this regard, Indeck as the permit applicant is generally under an obligation to undertake a significant effort to provide data and analysis in its application to support the determination of BACT for the proposed plant.[41]

In an ensuing letter, the State of Illinois then formally informed EPA that Illinois has "concluded that it is appropriate for applicants for [proposed coal-fired power plants] to consider IGCC as part of their BACT demonstrations."[42]

Similarly, the Georgia Department of Natural Resources, in a March 2002 letter regarding the permit application of Longleaf Energy Station, also relied, in part, on the failure of the permit applicant to consider cleaner coal combustion technology in finding the application deficient. In making its determination of deficiency, Georgia stated that the applicant did not "discuss any other methods from generating electricity from the combustion of coal, such as pressurized fluidized bed combustion or integrated gasification combined cycle."[43] Georgia further stated that the applicant "should discuss these technologies and explain why you elected to propose a pulverized coal-fired steam electric power plant instead."[44]

Reflecting the viability of IGCC, the State of New Mexico issued a letter on December 23, 2002 requiring the permit applicant for a new coal-fired power plant to conduct a site-specific analysis of IGCC as well as CFB as part of the BACT analysis for the proposed facility: "The Department requires a site-specific analysis of IGCC and CFB in order to make a determination regarding BACT for the proposed facility." The New Mexico determination goes

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[41] Letter from Illinois Division of Air Pollution Control to Jim Schneider, Indeck-Elwood, LLC (March 8, 2003), Attachment 12.

[42] Letter from Illinois EPA Director to EPA Regional Administrator, Region V (March 19, 2003), Attachment 13.

[43] Letter from James A. Capp, Manager, Stationary Source Permitting Program, Georgia DNR, to D. Blake Wheatley, Assistant Vice President, Longleaf Energy Associates, LLC (March 6, 2002). Attachment 14.

[44] *Id.*

on to provide: "The analysis must include a discussion of the technical feasibility and availability of IGCC and CFB for the proposed site in McKinley County, including a discussion of existing IGCC and CFB systems."[45]

On August 29, 2003, New Mexico issued its evaluation of the applicant's response. New Mexico found that the applicant's BACT analysis had in fact indicated that IGCC is commercially available but that the applicant had improperly relied on cost to find that the technology was infeasible:

> Mustang concludes that neither IGCC nor CFB are technically feasible control options for the Mustang site. After careful review of the revised BACT analysis, as well as information gathered from independent sources, the Department determines that Mustang's conclusion is not supported by the evidence. Accordingly, the Department finds that Mustang has not demonstrated the technical infeasibility of IGCC and CFB. Moreover, applying the criteria in the NSR Manual, the Department determines that IGCC and CFB are technically feasible at the Mustang site, and must be evaluated in the remaining steps of the top down BACT methodology.
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> (a) IGCC and CFB are technically feasible at the Mustang site. A technology is considered to be technically feasible if it is commercially available and applicable to the source under consideration. See NSR Manual at B.17-18. A technology is commercially available if it has reached a licensing and commercial sales stage of development. Id. A technology is applicable if it has been specified in a permit for the same or a similar source type. Id. Mustang's revised BACT analysis indicates that IGCC is commercially available, and IGCC has been specified in air quality permits for coal-fired power plants. See, e.g., Lima Energy Facility, 580 megawatt coal-fired power plant. Similarly, CFB is commercially available and has been specified in air quality permits for coal-fired power plants. See, e.g., AES Puerto Rico 454 megawatt coal-fired power plant; Reliant Energy Seward 584 megawatt coal-fired power plant.
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> (b) For both IGCC and CFB, Mustang improperly relies on cost to determine technical infeasibility. A technology is technically feasible when the resolution of technical difficulties is a matter of cost. See NSR Manual at B.19-20. Mustang's revised BACT analysis indicates that the resolution of technical difficulties for both IGCC and CFB are a matter of cost. These costs do not support a finding of technical infeasibility, but may be considered during Step 4

[45] Letter from New Mexico Environment Department to Larry Messinger, Mustang Energy Corporation (Dec. 23, 2002). Attachment 15.

of the top down BACT methodology. See NSR Manual at B.26.[46]

In addition, the Montana Board of Environmental Review has found that the state Department of Environmental Quality must consider IGCC as an available technology in the BACT review for a coal-fired power plant. Specifically, the Board of Environmental Review stated: "the Department should require applicants to consider innovative fuel combustion techniques in their BACT analysis and the Department should evaluate such techniques in its BACT determination in accordance with the top-down five-step method."[47]

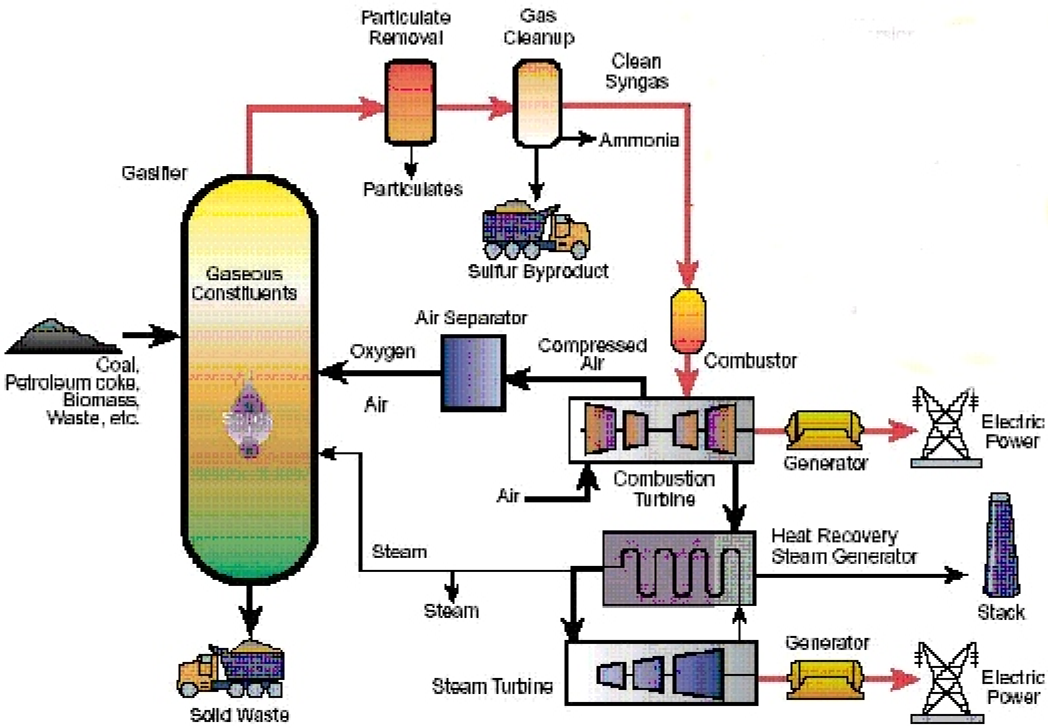
It would be arbitrary and capricious were South Dakota not to require consideration of IGCC as an available and technically feasible technology in the Big Stone II BACT analysis. The December 2002 and August 2003 New Mexico determinations and the March 2003 Illinois determination are attached hereto.

SDDENR Failed to Adequately Address IGCC in the BACT Analysis

IGCC is an available method, system and technique for curbing air pollutants from Highwood consistent with Montana's definition of BACT. Electricity generation from coal using IGCC technology is a commercially available and proven process. IGCC units generate electricity by integrating a coal gasifier with combined cycle (combustion turbine and steam turbine) electricity generation equipment (see figure below).

[46] Letter from New Mexico Environment Department to Larry Messinger, Mustang Energy Company (Aug. 29, 2003), at p. 3, Attachment 16.

[47] Montana Board of Environmental Review, Findings of Fact, Conclusions of Law, and Order In the Matter of the Air Quality Permit for the Roundup Power Project (Permit No, 3182-00), Case No. 2003-04 AQ (June 23, 2003) at 18-19.



Two full scale commercial IGCC electric generating units are in operation in the United States: Tampa Electric Company's 262 MW unit at the Polk plant in Florida and Cinergy's 192 MW unit at the Wabash River plant in Indiana, which both rely on coal as a fuel source.[48] Two other coal-based IGCC plants operate in Europe, NUON/Demkolec is a 253 MW plant in the Netherlands, and ELCOGAS in Spain is 298 MW.[49] IGCC units can be constructed with multiple gasifiers to achieve unit availability at levels comparable to those of conventional baseload facilities. For instance, the Eastman Chemical plant in Kingsport, Tennessee has utilized a dual-gasifier design to produce chemicals from syngas and has experienced 98 percent availability since 1986.[50] ChevronTexaco claims that its new Standard Project Initiative

[48] Resource Systems Group, Inc., EPIndex. *See* www.epindex.com

[49] Major Environmental Aspects of Gasification-Based Power Generation Technologies, Dec 2002, Table 1-7, page 1-26, Attachment 17.

[50] Smith, R.G., "Eastman Chemical Plant Kingsport Plant Chemicals from Coal Operations,1983-2000," 2000 Gasification Technologies Conference, Attachment 18.

Reference IGCC Plant achieves greater than 90% availability by using multiple gas trains.[51] Worldwide there are 131 gasification projects in operation with a combined capacity equivalent to 23,750 MW of IGCC units.[52] An additional 31 projects are planned that would increase this capacity by more than 50 percent.[53] Although not all of these projects produce electricity from coal, they demonstrate widespread commercial application of gasification technology for fuel processing, one of two key components of an IGCC plant. The second component is a combined cycle electricity generating system, which is now commonplace for new natural gas fired power plants.

IGCC units are available from major well-known vendors. Coal gasification equipment is available from GE[54] , Shell, and Global Energy, while major turbine manufacturers, including GE and Siemens-Westinghouse, provide combined cycle generators designed to run on the synthesis gas produced by coal gasifiers. Engineers from Texaco, Jacobs Engineering, and GE have teamed up to offer a standardized IGCC design.[55] James Childress, the Executive Director of the Gasification Technology Council, provided testimony to the U.S. Senate Environment and Public Works Committee stating, "[g]asification is a widely used commercially proven technology."[56] At the same hearing, Edward Lowe, Gas Turbine-Combined Cycle Product Line Manager for General Electric Power Systems, stated that, "IGCC is inherently less polluting and more efficient than any other coal power generation technology."[57] Likewise, the National Coal Council, in a May 2001 report, confirms that IGCC is "viable, commercially available

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[51] O'Keefe, L. and Sturm, K., "Clean Coal Technology Options - A Comparison of IGCC vs. Pulverized Coal Boilers," presentation to the 2002 Gasification Technologies Conference, October 2002, Attachment 19.

[52] Simbeck, Dale, SFA Pacific Inc. Gasification Technology Update, presented to the European Gasification Conference, April 8-10, 2002. The total capacity is based on output of synthesis gas. Many of these projects produce chemicals in addition to or instead of electricity.

[53] *Id.*

[54] On June 30, 2004, GE acquired the gasification business of ChevronTexaco.

[55]O'Keefe, Luke, et al. A Single IGCC Design for Variable CO2 Capture, Attachment 20.

[56] Childress, James M. Statement Submitted for the Record, Senate Environment and Public Works.

[57] Lowe, Edward. Outlook on Integrated Gasification Combined Cycle (IGCC) Technology. Senate Environment and Public Works Subcommittee on Clean Air, Wetlands and Climate Change, January 29, 2002.

technology."[58] ChevronTexaco, in an October 2002 presentation, states that, "IGCC is a current viable choice for clean coal capacity."[59] And the Center for Energy and Economic Development (CEED) states that, "IGCC technology is available for deployment today."[60]

The coal gasification fuel-processing step in IGCC power plants results in superior environmental performance and lower emissions compared to the CFB technology that is proposed for the Big Stone II power plant. Gasifying coal at high pressure prior to combustion facilitates removal of pollutants that would otherwise be released into the air. According to James Childress, "…criteria pollutant emissions for a coal-based IGCC plant are well below those of even the most modern pulverized coal plants with post combustion cleanup."[61] Mercury removal rates of greater than 90 percent can also be achieved using currently available control technologies with IGCC. DOE states that "an IGCC power plant has the potential of achieving very high mercury removal performance with established technology" and mercury removal in an IGCC power plant can be expected to be very high in removal effectiveness, low in cost, and reliable in design."[62]

Table 1 summarizes the Big Stone II draft permit emission rates with permit emission rates for an IGCC plant using the design fuel for Big Stone II. For each of the important pollutants in the BACT analysis, IGCC is the top ranked technology or is equivalent to the proposed Big Stone II emission limits.

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[58] National Coal Council, Increasing Electricity Availability from Coal-Fired Power Plants in the Near Term, p. 20 (May 2001), Attachment 21.

[59] "Clean Coal Technology Options - A Comparison of IGCC vs. Pulverized Coal Boilers," Luke O'Keefe and Karl Sturm (ChevronTexaco), October 28, 2002, p. 8. Attachment 19.

[60] *See* www.ceednet.org/fueling/investing.asp.

[61] Childress, James M. Statement Submitted for the Record, Senate Environment and Public Works Subcommittee on Clean Air, Wetlands and Climate Change, January 29, 2002.

[62] "The Cost of Mercury Removal in an IGCC Plant," US DOE, NETL, September 2002 at 1-2, Attachment 22.

Table 1: Emission Rates

	Big Stone II Proposed Emission Rates (lb/MMBtu)	**IGCC Permit Emission Rates* (lb/MMBtu)**
PM10	0.012	0.011
VOC	0.0036	0.0017
CO	0.15	0.03
H2SO4	0.005	0.0005
Hg	none	0.00000056
SO_2	0.20**	0.03
NO_x	0.14**	0.07

*IGCC Permit Emission Rates from the Elm Road Wisconsin permit issued by WDNR January 2004, expressed in lb/MMBtu.

**The SO_2 and NO_x NSPS limits, in the draft permit in terms of lb/MWh, were converted to lb/MMBtu assuming 48% gross efficiency of the supercritical boiler planned for Big Stone II.[63]

[63] The gross efficiency used in this calculation is based on EPA's assessment that new supercritical boilers can achieve net efficiencies as high as 45%. A net efficiency of 45% is equal to a gross efficiency of about 48%, assuming an auxiliary power efficiency of about 93%.

For the limits found in Table 1 under baseload conditions, IGCC would yield lesser amounts of all criteria pollutants and significantly lower amounts of the climate changing emissions of CO2. Sulfur dioxide can be readily controlled by 98-99.5%, and mercury can be readily controlled by 90-95%.[64] Furthermore, IGCC allows for an option to make even deeper cuts in carbon dioxide that conventional coal plants cannot do. The CO2 in the syngas can be captured and sequestered at a fraction of the cost of post-combustion carbon capture and sequestration at other coal plants.

The waste leaving an IGCC plant is vitrified, thereby potentially reducing some of the solid waste disposal issues associated with coal combustion. Indeed, IGCC plants produce 30-50% less solid waste than conventional coal-fired power plants.[65] South Dakota has a duty under federal and state law to consider the environmental impacts of the solid waste associated with different technology options.

IGCC is clearly an available method, system and technique for producing electricity from subbituminous coal and thus must be fully and fairly evaluated in the Big Stone II BACT analysis. Otter Tail and/or SDDENR must develop average and incremental costs for each pollutant removed and compare these costs to the proposed configuration of the Big Stone II facility.

XII. THE PROPOSED PM_{10} BACT EMISSION LIMITS FAIL TO REFLECT THE MAXIMUM LEVEL OF CONTROL THAT CAN BE ACHIEVED

SDDENR's draft PM_{10} BACT limit for the Big Stone II boiler does not reflect the maximum level of control that can be achieved. SDDENR did not even conduct a true top-down review of BACT for PM_{10} from the Big Stone II boiler. SDDENR indicates in its Statement of Basis that a baghouse is the top level of control and thus no additional review of controls is required, just a review of collateral impacts and determining a particulate matter limit. Statement of Basis at 16. However, as is shown by the variety of PM_{10} emission limits that have recently been required as BACT in Table 10-5 of the Statement of Basis, there are varying levels of control with the same technology. Specifically, different types of bags can be used in the baghouse, such as Teflon coated or "GoreTex", to achieve greater removal efficiency. SDDENR and Otter Tail must evaluate the various types of specialty bags available in the BACT analysis to ensure that Big Stone II meets a PM BACT limit reflect of the maximum degree of reduction of PM achievable, as required by the definition of BACT. See 40 C.F.R. §52.21(b)(12).

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[64] "IGCC's Environmental and Operational Capabilities Today," Workshop on Gasification Technologies, June 8, 2004, David L. Denton (Eastman Gasification Services Company), Attachment 23.

[65] Major Environmental Aspects of Gasification-Based Power Generation Technologies, US DOE, December 2002, Table 1-7, Page 1-27, Attachment 17.

Further, SDDENR limited its PM_{10} BACT review for the boiler to only those BACT limits in the RACT/BACT/LAER Clearinghouse (RBLC) for pulverized coal boilers burning subbituminous coal. There is absolutely no adequate rationale for limiting the review of PM_{10} BACT only to boilers burning subbituminous coal, or only to boilers using pulverized coal technology. Also, SDDENR must not limit its BACT review only to those facilities with permit information entered into the RBLC. SDDENR must also consider permits that have not yet been entered into the system, complete PSD permit applications, proposed permits, as well as technical journals and information from control technology vendors and experiences of other sources including performance tests.

Several recently permitted and constructed coal-fired power plants are subject to more stringent PM BACT limits than the 0.012 lb/MMBtu (filterable) PM_{10} limit or the 0.03 lb/MMBtu PM10 (filterable plus condensible) proposed by SDDENR for Big Stone II. For example, the Northampton Generating Station in Pennsylvania is subject to a much lower PM_{10} limit of 0.0088 lb/MMBtu, and this emission limit is easily being met (Attachment 24). The proposed Longview Power Plant has a total PM_{10} BACT limit of 0.018 lb/MMBtu (Attachment 25). The Trimble County Generating Station also has a total PM limit of 0.018 lb/MMBtu (Attachment 26). Thus, SDDENR must consider these much lower emission limits in its BACT evaluation for Big Stone II.

SDDENR also must review the emission rates that have been achieved in practice from the use of baghouses on coal-fired boilers. Indeed, performance test data for a number of facilities indicate that lower filterable PM_{10} emission rates can be achieved. For example, the state of Florida has a searchable database of such performance tests. SDDENR must base the PM_{10} BACT limit on the maximum achievable emission reduction rate, not only the emission limitations required of other recently permitted sources.

The BACT analysis for Big Stone II must also include a visible emission limit reflective of BACT for the source. The definition of BACT at 40 C.F.R. §52.21(b)(12) specifically indicates that BACT includes a "visible emission limitation." The state and NSPS opacity limit fo 20% does not reflect BACT. Indeed, with a fabric filter baghouse for PM_{10} control, an opacity BACT limit should be at least 10%. The state of Utah recently issued two permits for coal-fired power plants to be equipped with fabric filter baghouses - Intermountain Power Unit 3 (Attachment 27) and the Sevier power plant (Attachment 28) - which both have 10% opacity limits required as BACT. Thus, SDDENR must include an evaluation of opacity BACT in its Statement of Basis and must impose a visible emission limit on Big Stone II that reflects the maximum degree of reduction achievable.

In summary, SDDENR must revise its BACT analysis for the Big Stone II boiler to ensure that filterable PM_{10}, total $_{PM10}$ and opacity limits are imposed that reflect the maximum degree of reductions that can be achieved.

XIII. THE H_2SO_4 EMISSION LIMIT DOES NOT REFLECT BACT

SDDENR proposed an H_2SO_4 emission limit of 0.005 lb/MMBtu based on the planned wet scrubber and baghouse planned for SO_2 and PM10 control at Big Stone II. Otter Tail and SDDENR eliminated consideration of the top control option, a wet electrostatic precipitator (ESP), because a wet ESP had not been required for control of H_2SO_4 emissions from a pulverized coal boiler burning subbituminous coal. As stated above, there is no justification to limit the Big Stone II BACT review to only those pulverized coal boilers burning subbituminous coal. Thus, Otter Tail and SDDENR must analyze application of a wet ESP for H_2SO_4 control in its BACT analysis. It must be noted that Otter Tail's analysis that a wet ESP was cost prohibitive, which could not be found in Otter Tail's permit application, must be reviewed against the costs that had to be borne by other coal-fired power plants using wet ESPs for H_2SO_4 control. SDDENR cannot determine that a wet ESP is not economically feasible without such a comparison.

There are other feasible options that can be used to control H_2SO_4 , including sorbent injection, a low SO_2 to SO_3 conversion SCR catalyst[66], lowering the temperature across the SCR catalyst using more frequent soot blowing[67], a more efficient SO_2 scrubber (such as the Chiyoda bubbling jet reactor), regenerating the SCR catalyst rather than replacing it[68], and combinations of these control options[69].

A significant fraction of the H_2SO_4 is created by the SCR, which is proposed to control NO_x. The SCR catalyst converts SO_2 created in the boiler to SO_3, which subsequently combines with water to form H_2SO_4.[70] Conversion rates of less than 1% are feasible, and any reduced

[66] J. Cooper and others, First Application of Babcock-Hitachi K.K. Low SO_2 to SO_3 Oxidation Catalyst at the Petersburg Generation Station, ICAC 2005; Low SO_2 Oxidation Rate for Hitachi Catalyst, FGD & DeNOx Newsletter, No. 293, September 2002; Morita and others, Development and Operating Results of Low SO_2 to SO_3 Conversion Rate Catalyst for $DeNO_X$ Application.

[67] Rick Lausman, Impacts of Plant Operations on Opacity and Particulate Emissions, Black & Veatch, July 28, 2005.

[68] D.W. Bullock and others, Full-Scale Catalyst Regeneration Experience at the Coal-Fired Indiantown Generating Plant, DOE 2003 SCR/SNCR Workshop; M. Cooper, New Life for Old Catalyst, Power Engineering, March 2006.

[69] K. Dombrowski and others, SO_3 Mitigation Guide and Cost Estimating Workbook, Mega 2004; AEP, General James M. Gavin Plant, Feasibility of Alternative SO_3 Plume Mitigation Strategies, June 1, 2002.

[70] R.K. Srivastava and others, Emissions of Sulfur Trioxide from Coal-Fired Power Plants, J. Air & Waste Manage. Assoc., v. 54, 2004, pp. 750-762

catalyst reactivity can be overcome by using a more reactive catalyst formulation or modifying the catalyst management plan.[71]

In addition, much lower H_2SO_4 limits have been required at recently permitted coal-fired power plants, including the Sevier power plant (H_2SO_4 BACT limit is 0.0024 lb/MMBtu, *see* Attachment 31) and MidAmerican Energies Council Bluffs Unit 4 (as indicated in Otter Tail's RBLC printout in Appendix D of the Big Stone II permit application). SDDENR must evaluate these lower H_2SO_4 limits in the BACT analysis for Big Stone and provide sufficient justification for its H_2SO_4 BACT determination.

XIV. THE BACT LIMITS MUST MEET ENFORCEABILITY CRITERIA

All BACT limits must be enforceable and thus must include provisions to ensure enforceability, but the draft Big Stone II permit does not include such provisions. Specifically, as discussed in EPA's October 1990 Draft New Source Review Workshop Manual, "BACT emission limits or conditions must be met on a continual basis at all levels of operation (e.g., limits written in lb/MMBtu or percent reduction achieved), demonstrate protection of short term ambient standards (limits written in pounds per hour) and be enforceable as a practical matter (contain appropriate averaging times, compliance verification procedures and recordkeeping requirements)." (NSR Workshop Manual at B.56). SDDENR did not propose sufficient conditions to ensure the enforceability of its proposed BACT limits.

With respect to all of the emission limits, there must be pound per hour emission caps established, in addition to lb/MMBtu limits, reflective of BACT and consistent with what is modeled to show compliance with the NAAQS and PSD increments. The October 1990 Draft NSR Workshop Manual indicate that it is best to express emission limits in two different ways, "with one value serving as an emissions cap (e.g., lb/hr) and the other ensuring continuous compliance at any operating capacity (e.g., lb/MMBtu)." *See* NSR Workshop Manual at H.5.. *See also In re Steel Dynamics, Inc.*, PSD Appeal Nos. 99-4 & 99-5, Decided June 22, 2000, at 220-225. For all pollutants except PM, SDDENR only proposed lb/MMBtu emission limits, and has not proposed any enforceable cap on hourly emissions. There also is no limit on hourly heat input in the Big Stone II proposed permit. Thus, there is no assurance that the hourly emission rates used in the modeling analyses (as shown in Table 10-16 of the Statement of Basis) will actually be complied with. Absent pound per hour emission caps, or a maximum hourly heat input cap that could be used to convert lb/MMBtu emission limits to a max lb/hr limit, modeling analyses for Big Stone II must evaluate the impacts of the facility's uncontrolled emissions.

Further, the averaging time of the BACT emission limits must be consistent with the averaging time of the short term NAAQS and PSD increments, including a 24-hour averaging time for PM_{10} limits, an 8-hour averaging time for CO limits, and an 8-hour averaging time for

[71] J. Cooper and others, First Application of Babcock-Hitachi K.K. Low SO_2 to SO_3 Oxidation Catalyst at the Petersburg Generation Station, ICAC 2005.

VOC limits. In addition to being discussed in the New Source Review Workshop Manual, this is also discussed in a November 24, 1986 memo from the Director of EPA's Office of Air Quality Planning and Standards, which states that it is EPA's national policy that PSD permits must contain short term emission limits to ensure protection of the applicable NAAQS and PSD increments.

The permit must also specify appropriate compliance methods and recordkeeping requirements to show compliance with these emission limits. As discussed in the NSR Workshop Manual, "the construction permit should state how compliance with each limitation will be determined." (*See* NSR Workshop Manual at H.6.). The test methods must provide for continuous compliance where feasible. While SDDENR is requiring continuous compliance test methods for opacity, CO, SO_2, and NO_x, continuous emission monitors are also available for PM_{10}. SDDENR must require continuous monitoring for the PM10 emission limits. SDDENR also has not specified test methods for any of the other proposed BACT emission limits for the various units at the Big Stone facility. The Big Stone II permit must specify test methods for all emission limits. Further, the permit must include provisions for compliance testing in addition to the initial performance testing. BACT is to be met on a continual basis, and thus compliance must be demonstrated on a continual basis - not just initially after completion of construction.

Once a BACT visible emission limit is added to the permit, *see* Section XI above, for the reasons stated above, COMS must be specified as the method for determining compliance.

XV. SDDENR CANNOT EXEMPT EMISSIONS DUE TO STARTUP OR SHUTDOWN FROM BACT OR MODELING EMISSION LIMITS

Section 6.3 of the draft permit for Big Stone II indicates that operations during periods of startup, shutdown, and malfunction "shall not constitute representative conditions for the purpose of a performance test." The draft permit indicates that this provision stems from 40 C.F.R. §60.8(c) (incorporated into the ARSD at §74:36:07:01). However, unlike many of the NSPS emission limits, BACT emission limits must apply at all times including startup, shutdown and malfunction. Emission limits defined as BACT under the PSD program are established under the state implementation plan and are intended to protect ambient air standards. The ambient air quality standards are to be met on a continuous basis. Thus compliance with the BACT limits must also be on a continuous basis. For the same reasons, compliance with any of the emission limits used in the ambient air modeling analysis must also include emissions during startup, shutdown and malfunction.

Section 302(k) of the Clean Air Act expressly defines the term "emission limitation" as a limitation on emissions of air pollutants "on a continuous basis." Section 169(3) of the Clean Air Act, in turn, defines BACT as an "emission limitation." Accordingly, the Clean Air Act mandates that BACT continuously limit emissions of air pollutants. EPA's January 28, 1993 guidance memo entitled "Automatic or Blanket Exemptions for Excess Emissions During Startup, and Shutdowns Under PSD" specifically disallows automatic exemptions from BACT emission limits. Thus, the permit for Big Stone II must ensure that BACT emission limits and modeling emission limits are met at all times, and thus the provision in Section 6.3 of the draft permit cited above must be deleted.

XVI. THE HURON AIRPORT METEOROLOGICAL DATA ARE UNACCEPTABLE FOR AIR DISPERSION MODELING

The PSD Application assesses compliance with the NAAQS and PSD increments using five years of meteorological data (2000 through 2004) from Huron Airport. The airport data, collected at a location roughly 100 miles from Big Stone II, is neither site-specific nor is the quality of the data acceptable for air dispersion modeling. The Big Stone II PSD Application, which relies on these data for air modeling, is therefore flawed.

For air dispersion modeling purposes, airport data are among the least desirable. Problems with location and the general quality of data are the primary concerns. EPA, in their Meteorological Monitoring Guidance for Regulatory Modeling Applications, summarizes these concerns about using airport data:

> For practical purposes, because airport data were readily available, most regulatory modeling was initially performed using these data; however, one should be ware that airport data, in general do not meet this guidance.[72]

First and foremost, the Huron Airport data are not site-specific to the Big Stone II facility. The distance involved (about 100 miles) makes the airport data clearly not site-specific, with numerous land use classifications existing between Big Stone II and the airport. Most important, however, are the difference in land uses at Big Stone II and the airport, respectively. Huron Airport is comprised of concrete runways, parking lots, passenger terminals, and other structures associated with air travel activities. These surface and building characteristics in turn affect the boundary layer meteorology present at the airport.[73] In addition, landings, takeoffs, and idling of airplanes affect the site-specific conditions at the airport such that the meteorological conditions are not representative of the area surrounding the Big Stone II facility (which is adjacent to a water body).

The major issue, however, is the quality of the meteorological data collected at Huron Airport. It is important to remember that the airport data are not collected with the thought of air dispersion modeling in mind. For example, airport conditions are typically reported once per hour, based on a single observation (usually) taken in the last ten minutes of each hour. EPA recommends that sampling rates of 60 to 360 per hour, at a minimum, be used to calculate

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[72] EPA, Meteorological Monitoring Guidance for Regulatory Modeling Applications, EPA-454/R-99-05, February 2000, p. 1-1.

[73] Oke T.R., Boundary Layer Climates, Halsted Press, 1978, pp. 240-241.

hourly-averaged meteorological data.[74] Air dispersion modeling requires hourly-averaged data, which represents the entire hour being modeled, not a snapshot taken in one moment during the hour.

In addition, data collected at Huron Airport are not subject to the system accuracies required for meteorological data collected for air dispersion modeling. EPA recommends that meteorological monitoring for dispersion modeling use equipment that are sensitive enough to measure all conditions necessary for verifying compliance with the NAAQS and PSD increments. For example, low wind speeds (down to 1.0 meter per second) are usually associated with peak air quality impacts - this is because modeled impacts are *inversely* proportional to wind speed. Following EPA guidance, wind speed measuring devices (anemometers) should have a starting threshold of 0.5 meter per second or less.[75] Furthermore, wind speed measurements should be accurate to within plus or minus 0.2 meter per second, with a measurement resolution of 0.1 meter per second.[76]

The Huron Airport data used by Otter Tail, rather than being measured in 0.1 meter per second increments, is based on wind speed observations that are reported in whole knots. *See* meteorological data files used in the PSD Application modeling analysis. Every modeled hourly wind speed is a factor of approximately 0.51 or 0.52 meter per second (the units required for input to the air dispersion model), which exists because one knot equals 0.51479 meter per second. The once-per-hour observations at Huron Airport (in whole knots, no fractions or decimals) were converted to meters per second and can therefore be back-converted to the whole knot measurements originally reported by the airport.

To further exemplify the problem of using the airport data, the lowest wind speed included in the meteorological data files used in the PSD Application (with no exceptions) is 1.56 meters per second (three knots). Out of a possible 43,828 hours in the five-year modeling data set, there are zero hours with reported wind speeds equal to 1.03 meters per second (two knots). In addition, all winds lower than three knots are reported as calms, and are thus excluded from the modeling analyses. There are 2,518 such calm hours in the meteorological data files used in the Big Stone II PSD Application. In no uncertain terms, the conditions most crucial for verifying compliance with the NAAQS and PSD increments (low wind speeds) are being excluded from the Big Stone II analysis because of the choice to use the airport data.

Sensitive and accurate measurements of wind speeds are necessary for measuring winds down to 0.5 meter per second (about one knot), which can then be used as 1.0 meter per second in the air dispersion modeling analyses. There would be no need to label such low wind speed hours as calm, which will greatly increase the number of hours included in the modeling

[74] EPA, Meteorological Monitoring Guidance for Regulatory Modeling Applications, EPA-454/R-99-05, February 2000, p. 4-2.
[75] *Id.*, p. 5-2.
[76] *Id.*, p. 5-1.

analyses. Again, it is these low wind speed hours which must be included in the modeling data set to verify compliance with the NAAQS or PSD increments. The meteorological data used in the PSD Application includes zero hours out of five years with a wind speed below 1.56 meters per second, and to compound the problem, lists all other wind speeds less than three knots as calms, which are then excluded from the model calculations.

We examined the effect of calm hours on the highest second high (HSH) 24-hour PM_{10} modeled concentrations analyzed in the PSD increment consumption analysis. As part of their PSD application, Otter Tail performed modeling that showed a HSH 24-hour PM_{10} concentration of 29.64 $\mu g/m^3$ - a value equal to 98.8% of the allowable increment of 30 $\mu g/m^3$. This is the result obtained with the ISCST3 calm processing approach which excludes calm hours from the modeling calculations.

The simplest method for examining the effect of calm hours on the HSH 24-hour PM_{10} concentrations is to use the ISCST3 non-default option, NOCALM. In essence, NOCALM includes all calm hours in the modeling calculations by setting the "calm" wind speed of 0.0 m/s to 1.0 m/s. This can be verified by using the default calm processing option, and manually changing all hours with 0.0 m/s winds to 1.0 m/s in the meteorological data sets from Huron Airport - the results are the same. Using the NOCALM option increases the HSH 24-hour PM_{10} concentration from 29.64 $\mu g/m^3$ to 39.27 $\mu g/m^3$, which significantly exceeds the allowable increment of 30 $\mu g/m^3$.

Applying NOCALM processing, however, comes with some valid criticism. In certain circumstances, several or more consecutive calm hours may occur in the meteorological Huron Airport data set. Calm hours are identified with wind speeds of 0.0 m/s, and for these hours the flow vector (direction towards which the wind is blowing) is set equal to the last non-calm hour value and then randomized within a 10 degree sector. Thus, a relatively narrow band of flow vectors could occur within consecutive calm hours. This leads to relatively higher modeled concentrations due to winds repeatedly impacting the same receptors.

While the application of NOCALM processing may appear to be overly conservative, it is more appropriate for verifying PSD increment concentrations than simply excluding the calm hours as was done in the Big Stone II PSD application. This is because using Huron Airport data and then excluding the calm hours does not verify compliance with the applicable standards and increments - the most critical condition necessary for confirming compliance are eliminated from the data set.

To further examine the effect of including calm hours on modeled concentrations, we analyzed the effect of setting calm hour winds to 1.0 m/s, and then randomizing the associated hourly flow vectors within wider sectors than the 10 degrees included in the Huron Airport data set. This has the advantage of including the calm hours in the modeling database, while not assessing impacts within a narrow band of flow vectors should consecutive calm hours exist.

This analysis was performed using the Huron Airport meteorological data and a processing program that changes calm hour winds to 1.0 m/s while randomizing the associated flow vector within a specified sector width. The FORTRAN code to the program we created is attached in Attachment 31. While it is virtually impossible to tell whether all calm hours should be modeled with 1.0 m/s winds (some hours will actually be calm), the actual number of true calms should be very small. Typically, when properly measured with modern anemometers, there are only a few calm hours in a meteorological data base per year.[77]

The results of our calm hour modeling analysis are shown in the table below. By including calm hours in the modeling data set, and randomizing the coupled flow vectors within a 30 degree sector, the HSH 24-hour PM_{10} modeled concentration is 31.45 $\mu g/m^3$. Increasing the sector width of random flow vectors to 60 degrees results in a HSH 24-hour PM_{10} modeled concentration of 31.97 $\mu g/m^3$; randomizing flow vectors within a very-wide 90 degree sector width still results in a HSH 24-hour PM10 modeled concentration of 34.86 $\mu g/m^3$. All of these examples exceed the PSD allowable increment of 30 $\mu g/m^3$. This analysis shows that Big Stone II emissions and assumptions as presented in their application, modeled with the wind conditions necessary for verifying compliance, will exceed allowable increments.

Year Met Modeled	Big Stone II Modeled	ISCST3 NOCALM Option	Min WS=1.0 m/s, Random FV within 30 degree sector	Min WS=1.0 m/s, Random FV within 60 degree sector	Min WS=1.0 m/s, Random FV within 90 degree sector
2000	24.80	30.14	30.06	26.81	26.37
2001	25.77	30.84	27.39	28.94	27.44
2002	29.64	32.21	31.45	31.97	34.86
2003	23.55	29.54	26.77	27.77	27.05
2004	23.49	39.27	29.01	28.71	26.74
Max	29.64	39.27	31.45	31.97	34.86

The extent of the sector width within which the flow vectors should be randomized is debatable; however, the conclusion that excluding calm winds from the data base is inappropriate is not. The table above clearly shows that recapturing the calm hours will significantly increase modeled concentrations. This is very important for verifying compliance

[77] For example, the pre-construction monitoring data set for the Newmont Nevada proposed coal-fired power plant has five calm hours (10 meter winds) in the one-year period from 9/1/2003 through 8/31/2004.

with applicable standards and increments, particularly when the applicant-modeled concentrations are already close to the threshold values.

Using airport data for modeling huge emitters of air pollutants, such as Big Stone II, must not be allowed. Excluding the calm hours from modeled concentrations reduces the predicted impacts - a benefit to Big Stone II and a detriment to the surrounding air quality. This is very convenient for the applicant, and helps to explain why complicated major sources of air pollutants still rely on antiquated airport meteorological data.

If Otter Tail insists on using Huron Airport data, which do not meet EPA requirements in the Meteorological Monitoring Guidance for Regulatory Modeling Applications, then they should be required to use ISCST3 with the non-default NOCALM option. Preferably, however, Otter Tail should have collected at least one-year of pre-construction meteorological data consistent with USEPA Meteorological Monitoring Guidance for Regulatory Modeling Applications. In any event, the current Big Stone II modeling is unacceptable for NAAQS and increment consumption analyses.

XVII. PRECONSTRUCTION MONITORING SHOULD HAVE BEEN REQUIRED

SDDENR should have required Otter Tail to collect pre-construction meteorological data for use in their PSD Application modeling. Big Stone II, which is a major emission source of many air pollutants, should not be assessed for PSD increment compliance using non site-specific meteorological data collected with none of the quality assurances necessary for air modeling data.[78]

Pre-construction meteorological data for projects that trigger PSD review is already being required for coal-fired power plants. Two recent projects in Nevada, Granite Fox Power (near Gerlach) and Newmont Nevada (Boulder Valley), have collected at least one year of pre-construction meteorological data. The data requirements, specific for input to air dispersion modeling for NAAQS and PSD increment analyses, are specified by the State of Nevada.[79] The State of Nevada Guidelines state: "Current on-site meteorological data are required for input to dispersion models used for analyzing the potential impacts from the air pollution sources at the facility."[80]

Even smaller air regulatory agencies have been requiring pre-construction meteorological data for many years. As part of their PSD program, the Santa Barbara County (California) Air Pollution Control district requires at least one-year of pre-construction air quality and

[78] EPA, Ambient Monitoring Guidelines for Prevention of Significant Deterioration (PSD), EPA-450/4-87-07, May 1987, p. 55.

[79] Nevada Bureau of Air Pollution Control, Ambient Air Quality Monitoring Guidelines, May 4, 2000.

[80] *Id.*, p. 6.

meteorological monitoring.[81] The meteorological monitoring requirements are specified in a detailed protocol that implements their PSD Rule.[82] PSD sources in Santa Barbara County must collect site-specific hourly-averaged values for the following meteorological parameters:

- Horizontal wind speed and wind direction (both arithmetic and resultant)
- Horizontal wind direction standard deviation (sigma theta)
- Standard deviation of wind speed normal to resultant wind direction (sigma v)
- Vertical wind speed
- Vertical wind speed standard deviation (sigma w)
- Standard deviation of the vertical wind direction (sigma phi)
- Ambient air temperature
- Shelter temperature[83]

The Big Stone air emissions are enormous and are released in a complex arrangement of point, area, and volume sources. Using an antiquated, low-quality, and non site-specific meteorological data set, for no other reason than to expedite the permitting process for the applicant, invalidates the entire air quality impact analysis. The PSD application should be denied because of this poor modeling practice, and not be resumed until Otter Tail has collected at least one year of site-specific meteorological data consistent with EPA's Meteorological Monitoring Guidance for Regulatory Modeling Applications.

XVIII. THE SO_2 MODELING ANALYSES ARE FLAWED

In addition to the issues with using meteorological data from the Huron Airport described above, Otter Tail's modeling analyses for the 3-hour average and 24-hour average SO_2 concentrations are flawed because there are no emission limitations consistent with the modeling that are required to be met at Big Stone I or Big Stone II on a 3-hour or 24-hour basis. In fact, each unit's short term average allowable SO_2 emission rates are much higher than what was modeled. Big Stone I has no limits on SO_2 emissions whatsoever. Thus, any modeling analysis of its emissions must be based on the worst case uncontrolled emission rate over a 3-hour and a 24-hour period from the unit. For Unit 2, no short term average enforceable limits have been proposed. Thus, its uncontrolled potential emission rate must be modeled, based on the maximum capacity of the unit to emit SO_2 over a 3-hour and a 24-hour period.[84] It is difficult to

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[81] Santa Barbara County Air Pollution Control District, Rule 803, Prevention of Significant Deterioration.

[82] Santa Barbara County Air Pollution Control District, Air Quality and Meteorological Monitoring Protocol for Santa Barbara County, October 1990.

[83] *Id.*, p. 57.

[84] The heat input capacity of Big Stone II of 6,000 MMBtu/hr was listed as the nominal heat input capacity by Otter Tail. The maximum heat input capacity must be used in determining allowable short term average emission rates, absent a limitation in the permit on

calculate the potential short term SO_2 emission rates from Big Stone II because Otter Tail failed to provide any data on the characteristics of the coal to be burned at Big Stone II. The 30-day average NSPS emission limit for SO_2 does not limit 3-hour and 24-hour average emission rates, and thus can't be considered as limiting short term SO_2 emissions from Big Stone II. Consequently, the short term potential emission rates of SO_2 at Big Stone II must be based on worst case uncontrolled SO_2 emission rates from subbituminous coal, and on the maximum potential heat input to the boiler.

Thus, in order for Otter Tail to have adequately demonstrated compliance with the SO_2 NAAQS, either the modeling must be redone to be based on maximum potential 3-hour and 24-hour emission rates from both Big Stone units or SDDENR must impose emission limits consistent with the emission rates modeled from each unit.

XIX. THE PM_{10} NAAQS AND INCREMENT MODELING ANALYSES ARE FLAWED

The PM_{10} NAAQS and increment modeling are flawed and underrepresent the ambient PM_{10} impacts expected with the operation of Big Stone II. Considering that the modeling analyses already predict concentrations that are 91% of the 24-hour average PM_{10} NAAQS and 98.8% of the 24-hour average PM_{10} increment, SDDENR must not issue the permit for Big Stone II without addressing all of the numerous flaws in the modeling analyses. As is shown in our discussion below, simply correcting some of the fugitive dust emission factors used indicates that Big Stone II would cause or contribute to violations of the 24-hour average PM_{10} NAAQS and the 24-hour PM_{10} increment. The issues described below are in addition to the problems with the meteorological data described above. Based on our modeling analyses, SDDENR cannot issue the permit for Big Stone II because of the predicted violations of the 24-hour PM_{10} NAAQS and increment.

A. Worst Case Emissions Must Be Modeled Or Enforceable Requirements Reflective of the Emission Rates Modeled Must Be Imposed

Otter Tail's modeling analysis for the 24-hour PM_{10} NAAQS is flawed because there are no enforceable emission limits reflective of the 24-hour average emission rates used in the modeling analysis. This is inconsistent with the PSD regulations which require Otter Tail to model allowable emissions to verify the source would not cause or contribute to a NAAQS violation. *See* 40 C.F.R. §52.21(k). For the Big Stone I facility, the PM_{10} emission rates modeled for Units #2-12 are significantly lower than the allowable PM_{10} emission rates for these units. See Attachment 29, 8/8/01 Title V permit, section 6.3.[85] For example, the allowable PM_{10}

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maximum heat input capacity of the Big Stone II unit.

[85] It appears that SDDENR may be modifying the Big Stone I Title V permitted PM emission rates in Condition 5.5 of the draft permit for Big Stone II. If these limits are being revised from lb/hour limits to limits on lb/MMBtu, gram per horsepower-hour, or grains/dscf,

emissions from the auxiliary boiler (Unit #2) are 85 pounds per hour, yet Otter Tail modeled this unit at 1.5 pounds per hour. For the Big Stone II boiler, an hourly emission rate of 180 lb/hr was modeled, but the permit does not include any requirement that ensures hourly emissions could not exceed 180 lb/hr, such as a limit on maximum hourly heat input to the boiler. Similarly, the hourly PM_{10} emission rates for the other emitting units at Big Stone II also have no basis in any enforceable emission limitations. Thus, the PM_{10} modeling analysis must be revised to be based on worst case 24-hour average emission rates, or the permit must be revised to specify the hourly emission rates assumed in the modeling as emission limitations.

B. Fugitive PM Emissions Were Greatly Underestimated

Our review of the applicant's modeling files indicates that fugitive dust from truck travel over haul roads is the major contributor to the project's impact on the 24-hour PM_{10} NAAQS and increment. A small increase in PM_{10} emissions from the haul roads would result in violations of both the 24-hour PM_{10} NAAQS and increment. The permit does not contain any BACT determination, emission limits, compliance provisions, or recordkeeping provisions for haul roads to assure that emissions remain below the levels assumed in the modeling.

Further, the applicant significantly underestimated haul road PM_{10} emissions by improperly applying an emission factor equation and by using an unrealistically low silt loading. These two errors combined underestimate haul road fugitive PM_{10} emissions by a factor of 7.6. Other fugitive emission sources were also underestimated.

We revised the PM_{10} modeling to correct these two errors in haul road emissions. The revised modeling indicates that the project will cause exceedances of both the 24-hour PM_{10} NAAQS and increment. The permit must be denied until and unless the applicant modifies the project to assure that the 24-hour PM_{10} NAAQS and increment are protected.

1. *Haul Road Emission Factor Equation*

Trucks will be used to haul limestone, fly ash, bottom ash, and gypsum. Trucks suspend dust on the haul road surface and shoulders of the road, creating fugitive PM10 emissions. These fugitive emissions are the main contributor to ambient PM10 concentrations because they are released near ground level.

The applicant estimated haul road PM_{10} emissions using a predictive emission factor equation for paved haul roads from AP-42, EPA's emission estimating manual. This equation allows one to calculate PM_{10} emissions from silt loading and truck weight. Silt loading is discussed in the next comment. This comment addresses the specific equation that should be used and the way it was used.

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these new emission limits do not effectively limit the allowable hourly emission rates consistent with the levels used in the PM_{10} modeling analyses.

AP-42 presents three different versions of the paved haul road equation, labeled Equation (1), Equation (2), and Equation (3). The applicant relied on Equation (3) but plugged in values for Equation (2). Equation (1) should have been used for 24-hour modeling.

Equations (2) and (3) were extrapolated from Equation (1) by the EPA by assuming that annual or other long-term average emissions are inversely proportional to the frequency of measurable precipitation. This is accomplished by adding a precipitation correction term. AP-42, p. 13.2.1-6. These are the wrong equations to use for 24-hour impacts, and, further complicating matter, Equation (3) was used, but variables corresponding to Equation (2) were plugged into it.

First, these latter two equations and specifically Equation (3) are not appropriate for determining 24-hour emissions because they are based on long-term annual average conditions which include assumptions about average patterns of precipitation. *See* discussion in AP-42, p. 13.2.1-6, which in turn refers to AP-42, Sec. 13.2.2, p. 13.2.2-7 (method originally derived for unpaved roads). The 24-hour dispersion analysis should be based on maximum 24-hour emissions, which would be higher than annual average emission because there is no precipitation on many days. An adjustment for precipitation based on long-term average weather patterns underestimates 24-hour emissions and thus 24-hour ambient impacts. Equation (1) should be used to calculate maximum 24-hour impacts.

Second, notwithstanding the choice of the wrong equation, the applicant misapplied it. The precipitation correction term in Equation (3) is 1 - 1.2P/N, where P is number of **hours** with at least 0.01 inches of precipitation during the averaging period and N is the number of **hours** in the averaging period. AP-42, p. 13.2.1-7.

The applicant erroneously assumed, contrary to AP-42's dictates, that N is the number of **days** with at least 0.01 inches of precipitation and N is the number of **days** in the averaging period. Ap., Appx. C, p. 2 and Appx. F, p. 5. These definitions are appropriate for Equation (2), which the applicant did not use, but are not correct for Equation (3), which the applicant did use.

Finally, even given the applicant's theory of days versus hours, the equation makes no sense for 24-hour average emissions as, when correctly applied, it yields negative emissions. The applicant defines N as the number of days in the averaging period. The averaging period for purposes of 24-hour emissions is 1 day. The applicant calculated the emissions used in the 24-hour dispersion modeling assuming 365 days in the averaging period. If 1 day had been used, the precipitation correction term yields the value -119 (1 - 1.2x100/1), demonstrating the problems with the applicant's haul road calculation methodology.

The applicant estimated two emission factors using this erroneous methodology, 0.14 pounds per vehicle mile traveled ("lb/VMT") for trucks and 0.40 lb/VMT for the heavier CAT model used at the landfill. The corresponding emission factors calculated using Equation (1), the correct equation for 24-hour emissions, are 0.20 lb/VMT for trucks and 0.59 lb/VMT for the CAT. *See* calculations in Attachment 32. Thus, the use of the wrong haul road equation and misapplication of said equation underestimated haul road PM_{10} emissions by a factor of 1.5.

2. *Haul Road Silt Content*

Dust emissions from paved roads vary with the amount of silt on the road surface, referred to as "silt loading." The haul road PM_{10} emissions included in the modeling assume a background silt loading value of 0.6 g/m2, which the Application characterizes as the "ubiquitous baseline for <500 trucks per day." This value was taken from Table 13.2.1-3 of AP-42. Ap., Appx. C, p. 1 and Appx. F, p. 5. This AP-42 table reports silt loadings for typical urban roadways, not industrial roadways inside of a coal-fired power plant. This can be discerned by reading the text following the table, which notes, in reference to Table 13.2.1-2, that "[p]ublic paved road silt loadings are dependent upon: traffic characteristics (speed, ADT, and fraction of heavy vehicles); road characteristics (), local land use () and regional/seasonal factors ()." The text continues, presenting separate silt loading values for industrial roadways in Table 13.2.1-4.

The paved roads of interest here are within the boundary of an existing industrial site. Thus, they are industrial roadways. Silt loading values of industrial roads are much higher than 0.6 g/m2, vary greatly, and are reported elsewhere in the same chapter of AP-42, in Table 13.2.1-4. AP-42 encourages the collection of site-specific silt loading data (which could have been done here as this is an existing facility, but apparently wasn't). "In the event that site-specific values cannot be obtained, an appropriate value for an industrial road may be selected from the mean values given in Table 13.2.1-4…" AP-42, p. 13.2.1-10.

The industrial roadway table provides a range of mean silt loading values from 7.4 to 292 g/m2. AP-42, Table 13.2.1-4. The modeled haul road PM_{10} emissions are based on a silt loading value of 0.6 g/m2. If the lower end of the range were used to estimate haul road PM_{10} emissions, the truck emission factor would increase from 0.14 lb/VMT to 0.70 lb/VMT and the CAT emission factor would increase from 0.40 lb/VMT to 2.0 lb/VMT. Thus, the choice of an urban baseline silt loading underestimated PM_{10} emissions from haul roads by a factor of five.

We further note that most of the material being handled, fly ash and bottom ash, is essentially 100% silt. Spillage of hauled material will make up a large fraction of the surface dust. Thus, surface silt loadings on these haul roads could be quite high and should have been measured, as recommended by AP-42, as this is an existing facility.

3. *Haul Road Emissions Calculated From Emission Factor*

The applicant converted the emission factors expressed in lb/VMT into emissions in grams per second, which were then input into the dispersion model and used to calculate ambient PM_{10} concentrations. This conversion requires the total vehicle miles traveled for each road segment. The VMT is generally calculated from the number of trips and the miles per trip for each road segment, or the amount of material to be hauled per day per segment and the capacity of the trucks doing the hauling. We did not find the requisite information in the files produced in response to our document request. Further, we were unable to confirm the emission rates that were modeled based on exhaustive attempts to reverse engineer them.

We believe the requisite information is either imbedded in the original Excel spreadsheets used to calculate the emissions or is contained in a separate linked spreadsheet that was omitted from the application. We asked SDDENR for a copy of the haul road spreadsheets in native format (Excel, rather than pdf) so that we could inspect the cells and determine how the calculations were made. SDDENR indicated that they did not have the Excel spreadsheets, suggesting that they did not carefully review the emission calculations themselves (and if they had, they would have run into the same problem we did). We also requested that SDDENR request the Excel spreadsheets from the applicant. The requested spreadsheets were not available at the time these comments were filed.

4. *Unpaved Haul Roads*

The emission calculations assume that all haul roads either are or will be paved, pursuant to permit condition 4.6. However, it is generally not feasible to pave haul roads within landfills because these roads are periodically moved to accommodate the increasing size and shape of the pile. Landfill haul roads are generally assumed to be unpaved. Landfill haul roads emit more PM_{10} than any other road segment because heavier vehicles are used on them. Further, although not considered in the application, they would have a higher silt content than other haul roads because the materials handled in their vicinity are 100% silt. We did not correct the modeling for this issue but recommend that the applicant do so.

5. *Other Fugitive Emission Issues*

There are a number of other instances in which the applicant's fugitive emission calculations significantly underestimate PM_{10} emissions. Four of these are briefly discussed below.

First, the threshold friction velocity used to estimate storage pile wind erosion are generally far too high for all materials. Ap., Appx. F, Sec. 3.1. The landfill value, for example, was assumed to equal a default value for overburden. However, the landfill will contain fly ash and bottom ash, which are 100% silt. The finer the material, the lower the threshold friction velocity. Overburden, which comprises coarser fractions, is not an appropriate surrogate.

Second, the pile maintenance fugitive emissions for the landfill and inactive coal storage piles were calculated assuming a silt content of 2.2%. Ap., Appx. F, Sec. 3.2. This value is incorrect for both types of storage piles.

This value is referenced to a December 2003 version of AP-42, Table 13.2.4-1.

However, EPA's website[86] does not identify a December 2003 version. There are only two versions, a 1995 version and a draft 2006 version of Sec. 13.2.4. Both of these versions record a silt content for coal at western coal mines (i.e., PRB coals such as used by Big Stone) as 6.2%. AP-42, Table 13.2.4-1. This is consistent with AP-42 Sec. 11.9, which reports silt content for bulldozed western coal of 6.0% to 11.3% with a geometric mean of 8.6%. The 2.2% figure that the applicant used is for bituminous coal. Powder River Basin coal is noted for its higher silt content. Thus, the applicant should have used 8.6% for the inactive PRB coal pile. The landfill will contain fly ash and bottom ash, which are 100% silt. Thus, 100% should have been used for the landfill calculations.

Third, pile maintenance emissions were estimated using an emission factor equation for unpaved roads, rather than the more appropriate bulldozing equation from AP-42, Section 11.9. Pile maintenance involves periodic bulldozing of the pile surface to maintain its contours. The bulldozing equation is more appropriate as much more material is moves in bulldozing than is suspended by running heavy equipment over unpaved roads.

Fourth, all sources of fugitive emissions were not included in the emission inventory. We were unable to identify any emissions from ash dumping onto the landfill, material loading onto trucks, and material dumping from trucks.[87]

We did not revise the emission calculations for these sources and remodel the emissions, but it is imperative that Otter Tail address these deficiencies. Further, our review is not comprehensive due to the inability to obtain a copy of the emission calculation spreadsheets in native format. Thus, we urge SDDENR to conduct a comprehensive review of all emission calculations and require that the applicant remodel them.

6. *Our Revised Modeling With Corrected Haul Road Emission Factors Shows Violations of the 24-Hour Average PM_{10} NAAQS and PM_{10} Increment*

We revised the applicant's Class II impact modeling to use corrected haul road PM_{10} emissions, calculated as discussed above. We modeled two scenarios incorporating the correct fugitive PM_{10} haul road emissions.

a) Revised PM_{10} Emissions - Increasing Haul Road Emissions by a Factor of 7.6

We examined the effect of correcting the haul road PM_{10} emissions on the highest second high (HSH) 24-hour PM_{10} modeled concentrations analyzed in the PSD increment consumption and NAAQS analyses. As part of their PSD application, BSII performed modeling that showed a HSH 24-hour PM_{10} concentration of 29.64 $\mu g/m^3$ - a value equal to 98.8% of the allowable

[86] Accessed June 19, 2006: http://www.epa.gov/ttn/chief/ap42/ch13/index.html.
[87] *See, e.g.*, the Wisconsin Department of Natural Resources report, "Review of Particulate Matter Reporting for Coal Burning Facilities," March 21, 2006.

increment of 30 $\mu g/m^3$. This is the result obtained with the ISCST3 calm processing approach which excludes calm hours from the modeling calculations. Modeled concentrations resulting from recapturing the excluded calm hours are discussed in greater detail in our comment on air quality modeling.

We used the same air dispersion model, meteorological data, receptors, and emissions information as supplied by the applicant, with the exception that we increased the haul road PM_{10} emissions by a factor of 7.6. For the PSD increment modeling, the following haul road segments were corrected:

- Rock Roads - All
- Paved Roads - All
- Rock Road - Gypsum
- Rock Road - Limestone
- Rock Road - Bottom Ash
- Rock Road - New Fly Ash
- Rock Road - Landfill

Remodeling the PSD increment analysis with corrected haul road PM_{10} emissions substantially increases the modeled concentrations. As shown in Table 1, correcting the haul road PM_{10} emissions results in a HSH 24-hr PM_{10} concentration of 148.52 $\mu g/m^3$ - about five times the allowable increment of 30 $\mu g/m^3$.

Table 1
PSD Increment 24-Hr PM_{10} Modeling Results (in $\mu g/m^3$):
Haul Road $_{PM10}$ Emissions Increased by a factor of 7.6.
No additional control measures applied.

Year Met Modeled	HSH 24-Hr Big Stone II PM_{10} Modeled ($\mu g/m^3$)	XUTM Coordinate (m)	YUTM Coordinate (m)
2000	129.37	696353.8	5018894.0
2001	148.52	696396.0	5018897.0
2002	130.19	696305.4	5018893.0
2003	116.85	696305.4	5018893.0
2004	136.45	696305.4	5018893.0

Max	148.52		

The NAAQS modeling included the PSD increment haul roads (with different PM_{10} emissions to account for existing activity) as well as four additional haul road segments:

- Rock Road - Tires
- Paved Road - Tires
- Rock Road - Existing Bottom Ash
- Rock Road - Existing Fly Ash

The revised NAAQS analyses incorporating revised haul road PM_{10} emissions are shown in Table 2. Correcting the haul road PM_{10} emissions results in HSH 24-hour impacts of 249.98 $\mu g/m^3$ (without background concentrations), and 281.98 $\mu g/m^3$ (with background). Both modeled HSH concentrations, with and without background, significantly exceed the NAAQS of 150 $\mu g/m^3$.

Table 2:
NAAQS 24-Hr PM_{10} Modeling Results (in *g/m3):
Haul Road PM_{10} Emissions Increased by a factor of 7.6.
No additional control measures applied.

Year Met Modeled	HSH 24-Hr Big Stone II PM10 Modeled ($\mu g/m^3$)	Background 24-Hr PM10 Concentration[88]	HSH 24-Hr Big Stone II PM10 Modeled with Background	XUTM Coordinate (m)	YUTM Coordinate (m)
2000	169.69	32	201.69	695679.2	5018924.0
2001	249.98	32	281.98	695685.1	5018903.0
2002	203.15	32	235.15	695679.2	5018924.0
2003	165.78	32	197.78	695662.6	5018940.0
2004	193.61	32	225.61	695679.2	5018924.0
Max			281.98		

[88] PSD Application, p. 6-13.

b) Revised PM_{10} Emissions - Increasing Haul Road Emissions by a Factor of 7.6 and Applying a 50 Percent Control Efficiency for Daily Watering of Paved Roads

SDDENR has included a condition (Section 7.1) in the draft PSD permit to reduce fugitive dust emissions from paved road surfaces. This condition requires sweeping or water applications to reduce dust during spring, summer, and fall.[89] This type of fugitive dust control measure, if properly applied, typically reduces PM_{10} emissions by about 50 percent.[90] We question the enforceability of this condition, as it is vague and does not definitively require sweeping or water control on a given schedule. However, for the purpose of this analysis, we assumed this condition would result in a 50% reduction in PM_{10} emissions from paved roads.

Remodeling the PSD increment analysis with corrected haul road PM_{10} emissions and applying 50% control efficiency for sweeping and watering paved roads will still result in modeled concentrations that exceed the allowable 24-hour increment. As shown in Table 3, correcting the haul road PM_{10} emissions and using a 50% control reduction results in a HSH 24-hr PM_{10} concentration of 75.36 $\mu g/m^3$ - about 2.5 times the allowable increment of 30 $\mu g/m^3$.

Table 3
PSD Increment 24-Hr PM_{10} Modeling Results (in $\mu g/m^3$):
Haul Road PM_{10} Emissions Increased by a factor of 7.6.
50% control efficiency applied due to daily sweeping or watering roads.

Year Met Modeled	HSH 24-Hr Big Stone II PM_{10} Modeled ($\mu g/m^3$)	XUTM Coordinate (m)	YUTM Coordinate (m)
2000	64.75	696353.8	5018894.0
2001	75.36	696438.2	5018899.0
2002	65.24	696305.4	5018893.0
2003	61.89	696305.4	5018893.0
2004	71.53	696305.4	5018893.0
Max	75.36		

The revised NAAQS analyses incorporating revised haul road PM_{10} emissions and

[89] Draft PSD Permit, April 2006, p.14.
[90] Monterey Bay Unified Air Pollution Control District, CEQA Air Quality Guidelines, September 2002, Table 8-2.

applying 50% control efficiency for paved road sweeping and watering are shown in Table 4. Correcting the haul road PM_{10} emissions and using a 50% control reduction results in HSH 24-hour impacts of 128.51 $\mu g/m^3$ (without background concentrations). The HSH 24-hour NAAQS modeling (with background of 32 $\mu g/m^3$) is 160.51 $\mu g/m^3$. The modeled HSH concentration, with background conditions, will exceed the NAAQS of 150 $\mu g/m^3$.

Table 4:
NAAQS 24-Hr PM_{10} Modeling Results (in $\mu g/m^3$):
Haul Road PM_{10} Emissions Increased by a factor of 7.6.
50% control efficiency applied due to daily watering of roads.

Year Met Modeled	HSH 24-Hr Big Stone II PM_{10} Modeled ($\mu g/m^3$)	Background 24-Hr PM_{10} Concentration	HSH 24-Hr Big Stone II PM_{10} Modeled with Background	XUTM Coordinate (m)	YUTM Coordinate (m)
2000	93.82	32	125.82	695679.2	5018924.0
2001	128.51	32	160.51	695685.1	5018903.0
2002	106.55	32	138.55	694965.5	5019243.0
2003	100.56	32	132.56	694965.5	5019243.0
2004	108.69	32	140.69	695685.1	5018903.0
Max			160.51		

Thus, the permit for Big Stone II must be denied because the project as proposed to be permitted would result in violations of the 24-hour PM_{10} NAAQS and PM-10 increments.

C. Fugitive Emission Rates Are Not Reflected in Enforceable Emission Limits

The draft permit fails to establish any emission limits or other requirements for haul roads and other fugitive sources, beyond requiring paving. BACT is required for haul road and other fugitives and the permit must include BACT emission limits for them that “demonstrate protection of short term ambient standards (limits written in pounds/hour) and be enforceable as a practical matter (contain appropriate averaging times, compliance verification and recordkeeping requirements).” NSR Manual, p. B.56.

The fugitive PM_{10} emissions used in the air quality modeling are based on certain assumptions, set out in the Application, Appendices C and F. These include the amount of material hauled, the type of trucks, the presence of paving, operating hours, and a specific surface silt content. Some of these assumptions are unlikely to be valid. For example, it is unlikely that the silt content of surface roads is only 0.6 g/m2, as assumed in haul road emission calculations. This assumption appears to have been chosen to reduce ambient 24-hour PM_{10} concentrations to just below the 24-hour NAAQS and Class II increment. Further, we note that the modeling assumed traffic on the haul roads for only 8 hours per day, from 6 AM to 2 PM. Maximum impacts likely would occur during the omitted hours. Thus, the permit should explicitly limit operating hours for the haul roads from 6 AM to 2 PM, or the modeling should be revised to consider 24 hour per day operation. It is very important that these and other assumptions used to estimate haul road PM_{10} emissions be verified by actual monitoring, recordkeeping, and reporting.

The draft permit does not require any emission limits, emission testing, operational monitoring and measurement, emission monitoring, recordkeeping or reporting to determine compliance with the haul road and other fugitive emissions that were modeled (with the exception of landfill silt content in permit section 7.2). Thus, there is no assurance that the PM_{10} modeling accurately represents site operational and physical conditions. The fact that modeled concentrations are very close to the 24-hour PM_{10} NAAQS and increment supports the need to confirm the assumptions that the modeling was based on.

The draft permit does not require any demonstration that the haul road and other fugitive emissions will be less than or equal to those assumed in the dispersion modeling. The Permit should be modified to require a study to measure the key variables used in the emission calculations (e.g., haul road length, number of truck trips, truck weight, haul road surface silt content). Further, the draft permit does not require any restrictions on the emission generating activity, e.g., truck trips over paved haul roads, operating hours. The permit should be revised to limit the amount of material hauled to that assumed in the PM_{10} emission calculations and hours of operation to those actually modeled.

D. The PM_{10} NAAQS Modeling Failed to Include Sources in Minnesota

The PM_{10} NAAQS modeling is also flawed because no sources in Minnesota were included in the modeling. There are several sources across the border in Big Stone County and Lac Qui Parle County, Minnesota that could impact PM_{10} concentrations in the Big Stone impact area including:[91]

Barry Farmers Coop
Beardsley Farmers Elevator Company

[91] This information was collected from EPA's EnviroFacts Warehouse.

Bituminous Paving - Odessa
Bituminous Paving Incorporated - Ortonville
Farmers Coop - Ortonville
Ortonville Stone Company
Ortonville Stone Company - nonmetallic - Sioux Falls
Ag Processing Incorporated - A Cooperative
Associated Milk Producers Incorporated
Dawson Grain Inc
EPI Dawson Ethanol
Farmers Coop Dawson
Farmers Coop Elev
Henrich& Sons Incorporated
Land OLakes/Farmland Feeds
Louisburg Farm Elev
Madison Elevator
Madison Milling
Municipal Castings
Tofte Auto & Sales
Tri-Line Farmer Coop

Thus, for all of the above reasons, the PM_{10} modeling is flawed and cannot be relied on to ensure that Big Stone II won't cause or contribute to a PM10 NAAQS violation.

E. The Cumulative PM_{10} Increment Modeling Analysis Is Flawed

In addition to all of the above flaws in the PM_{10} modeling, the PM_{10} increment modeling analysis is also flawed because the cumulative analysis is incomplete. SDDENR indicated in its Statement of Basis that Big Stone II would be the only increment consuming source because the baseline date had not yet been triggered for Grant County. SDDENR is misinterpreting the PSD regulations and, in fact, the PM_{10} baseline date *has* been triggered for the entire state of South Dakota. Under the PSD regulations, the area in which the minor source baseline date is termed the "baseline area." Baseline area is defined as follows:

> any intrastate area (and every part thereof) designated as attainment or unclassifiable under section 107(d)(1)(D) or (E) of the [Clean Air] Act in which the major source or major modification establishing the minor source baseline date would construct or would have an air quality impact equal to or greater than 1 ug/m3 (annual average) of the pollutant for which the minor source baseline date was established.

40 C.F.R. §52.21(b)(15)(i).

Areas designated as attainment or unclassifiable under section 107 of the Clean Air Act are identified in 40 C.F.R. Part 81. For South Dakota, two PM_{10} attainment/unclassifiable areas are identified - the Rapid City area and the "Rest of State" area. 40 C.F.R. §81.342. Indeed, §81.342 makes clear that the "Rest of State" area denotes "a single area designation for PSD baseline area purposes." Thus, the PM_{10} minor source baseline date *has* been triggered for the "rest of state" area that Big Stone II will locate within. And the minor source baseline date for the "rest of state" area must be based on the first complete PSD permit application for a major source or major modification of PM10 submitted after August 7, 1977, which proposed to locate within the "rest of state" area or which would have a significant ambient impact of PM_{10} within the "rest of state" area. 40 C.F.R. §52.21(b)(14)(ii) and §52.21(b)(15)(i). SDDENR indicated in its Statement of Basis that the South Dakota Soybeans Processers triggered the minor source baseline date (apparently to be located in Brookings County). However, there was very likely an earlier permitted major source or major modification of PM_{10} that proposed to locate in the "Rest of state" area that triggered the minor source baseline date. SDDENR must determine the exact baseline date - likely in consultation with EPA since EPA was the PSD permitting authority in South Dakota until the state was delegated authority to implement the PSD program in the mid-1990's. Once the proper PM_{10} baseline date is determined for the "rest of state area," then a cumulative increment analysis must be conducted. Such a cumulative analysis must not only include increment-consuming sources in South Dakota, but also increment consuming sources in Minnesota. With respect to South Dakota sources, it appears that SDDENR previously determined which sources impacted the same significant impact area as Big Stone II. *See* attached June 6, 2005 email from Kyrik Rombough to Robynn Andracsek and Terry Graumann. It must be determined whether those sources are increment-consuming and the appropriate increment-consuming emissions must be included in the cumulative modeling analysis.

Major sources in Minnesota that constructed or modified after the particulate matter major source baseline date of January 6, 1975 can consume the available increment in South Dakota. In addition, all increases in emissions from *any* source in Minnesota that occurred after the South Dakota particulate matter minor source baseline date and that would affect air quality concentrations in the vicinity of the Big Stone plant also consume the available PM_{10} increment. A search in EPA's EnviroFacts Warehouse of just the two Minnesota counties that Big Stone's impact are partially encompasses, Big Stone County and Lac Qui Parle County, shows several sources that should have been reviewed for inclusion in Big Stone's PM10 increment analysis including:

Barry Farmers Coop
Beardsley Farmers Elevator Company
Bituminous Paving - Odessa
Bituminous Paving Incorporated - Ortonville
Farmers Coop - Ortonville
Ortonville Stone Company
Ortonville Stone Company - nonmetallic - Sioux Falls

Ag Processing Incorporated - A Cooperative
Associated Milk Producers Incorporated
Dawson Grain Inc
EPI Dawson Ethanol
Farmers Coop Dawson
Farmers Coop Elev
Henrich& Sons Incorporated
Land OLakes/Farmland Feeds
Louisburg Farm Elev
Madison Elevator
Madison Milling
Municipal Castings
Tofte Auto & Sales
Tri-Line Farmer Coop

SDDENR and Otter Tail must review the emissions of these Minnesota sources and any other Minnesota sources that could impact the PM_{10} increment in the Big Stone impact area and include those sources' emissions in a PM_{10} increment analysis.

Last, as discussed in the next comment, emissions from Big Stone I also consume the available PM_{10} increment. Thus, Big Stone I's PM_{10} emissions must also be modeled in a cumulative PM_{10} increment analysis.

All of these issues are very significant considering that Otter Tail's predicted impact is already predicted to consume 29.64 $\mu g/m^3$ of the 30 $\mu g/m^3$ PM-10 Class II increment. While SDDENR claims that this number is higher than the impact Big Stone II will actually have because SDDENR required more stringent PM_{10} BACT limits than those proposed by Otter Tail, SDDENR did not provide any revised analysis to show how much lower the total increment consumption would be. Further, Otter Tail significantly underestimated its own impacts because it underestimated fugitive emission sources as discussed in great detail above. Also, the modeled emission rates were much lower than the proposed allowable emissions rates. As discussed above, if Otter Tail would have more appropriately modeled its emissions and all increment consuming emissions, PM_{10} increment violations would have been shown.

SDDENR is prohibited from issuing a PSD permit for Big Stone II unless Otter Tail has demonstrated that its "allowable emission increases. . . in conjunction with all other applicable emission increases or reductions. . . would not cause or contribute to air pollution in violation of. . .any applicable maximum allowable increase over baseline concentration in any area." 40 C.F.R.§52.21(k)(2). To date, no adequate or complete demonstration has been made. Thus, SDDENR cannot issue the PSD permit for Big Stone II.

XX. BIG STONE I MUST ALSO BE MODELED AS AN INCREMENT-CONSUMING SOURCE

As discussed in great detail at the beginning of this comment letter, Big Stone I has undergone major modifications in several instances over the past ten years or so. According to the definition of "baseline concentration," the emissions from Big Stone I became increment-consuming emissions once the facility was modified after the major source baseline date (January 6, 1975 for SO_2 and PM and February 8, 1988 for NO2). Specifically, the definition of "baseline concentration" provides in pertinent part:

> . . .the following will not be included in the baseline concentration and will affect the applicable maximum allowable increases. . .Actual emissions, as defined in paragraph (b)(21) of this section, from any major stationary source on which construction commenced after the major source baseline date.

40 C.F.R. §52.21(b)(13)(ii)(a). See also 40 C.F.R. §52.21(b)(14).

"Construction" is defined in the PSD regulations as "any physical change or change in the method of operation (including fabrication, erection, installation, demolition, or modification of an emissions unit) that would result in a change in emissions." 40 C.F.R.§52.21(b)(8).

Thus, the emissions associated with a modification at Big Stone I occurring after the major source baseline date consume the available increment. *See* October 1990 New Source Review Workshop Manual at C.6.

This means that the emission increases associated with the change in the method of operation of Big Stone I in 1995 to switch burning lignite to subbituminous coal consumes the available PM_{10} and NO_2 increment.[92] The increases in emissions as a result of the changes to the boiler that increased capacity in 1998 also consume the available increment for NO_2 and PM_{10}. Further, the increase in emissions allowed by the modification to provide steam to the ethanol plant and the increase in emissions associated with the turbine efficiency improvement project consume the available SO_2, NO_2, and PM_{10} increments as well.

Thus, SDDENR must model Big Stone I's increment consuming emissions. SDDENR must first properly determine the minor source baseline dates for SO_2, PM_{10} and NO_2. As

[92] The change to the type of coal burned could also expand the SO_2 increment, but that depends on what the minor source baseline date is for SO_2 for the "rest of state" area. If the SO_2 minor source baseline date is after 1995, then the SO_2 reductions from burning subbituminous coal would only expand increment if made federally enforceable. Currently, there are no enforceable requirements that Big Stone I only burn subbituminous coal. Thus, it's possible the decrease in SO_2 emissions that has occurred would not be creditable. *See* page C.10 of the October 1990 New Source Review Workshop Manual.

discussed above, SDDENR does not have county-wide Section 107 attainment areas for PM_{10}, but instead Big Stone is located in the "rest of state" PM_{10} attainment area where the PM minor source baseline date has likely been triggered - probably many years ago. Similarly, the entire state of South Dakota is one section 107 attainment area for both SO_2 and NO_2. *See* 40 C.F.R. §81.342. Thus, SDDENR must determine the minor source baseline date for SO_2 and NO_x for the entire state area. Then, SDDENR must determine the increment-affecting emissions for all physical changes at the Big Stone I facility after the major source baseline dates, and model those increment consuming emissions along with the proposed Big Stone II facility in cumulative increment consumption analyses. This appears to be especially significant for the Class II PM_{10} increment. With Big Stone II consuming 29.64 ug/m3 of the allowable 30 ug/m3 PM_{10} increment, it extremely likely that the PM_{10} Class II increment will be violated once Big Stone I's increment consuming emissions are included along with all other increment consuming emissions. SDDENR is prohibited from issuing the permit for Big Stone II without ensuring that Big Stone II won't cause or contribute to a violation of any increment. This determination must be made based on a proper and complete increment consumption analysis. Until such an analysis is completed, SDDENR cannot issue the permit to Big Stone II.

XXI. ENDANGERED SPECIES ACT.

SDDENR has utterly failed to carry out its obligations as an agent of the federal government with respect to the Endangered Species Act.

CONCLUSION

Thank you for consideration of these comments. Please include my name on the mailing list for any and all future actions regarding this proposed permit for Big Stone II and any actions related to our comments.

Yours Sincerely,

/s/

George E. Hays

List of Attachments

1. January 14, 1975 permit to operate issued by South Dakota to Otter Tail, transmitted to Otter Tail via a January 22, 1975 letter

2. May 5, 1975 letter from Otter Tail to South Dakota indicating its start of commercial operation of Big Stone I

3. XL Spreadsheet

4 Big Stone Plant Fuel Burn Record Summaries

5. November 28, 2000 Application for Minor Permit Amendment to Big Stone I Title V Permit re Supply of Steam to the Northern Growers Cooperative Ethanol Plant

6. January 10, 2001 Letter from Otter Tail to SSDENR

7. April 2, 2001 Letter from Otter Tail to SSDENR

8. June 19, 2001 email from Terry Grauman, Otter Tail, to Brian Gustafson, SDDENR

9. May 4, 2004 Letter from Otter Tail to SDDENR

10. May 20, 2004 Letter from Otter Tail to SDDENR

11. Considering Alternatives: The Case for Limiting CO2 Emissions from New Power Plants through New Source Review by Gregory B. Foote

12. Letter from Illinois Division of Air Pollution Control to Jim Schneider, Indeck-Elwood, LLC (March 8, 2003)

13. Letter from Illinois EPA Director to EPA Regional Administrator, Region V (March 19, 2003)

14. Letter from James A. Capp, Manager, Stationary Source Permitting Program, Georgia DNR, to D. Blake Wheatley, Assistant Vice President, Longleaf Energy Associates, LLC (March 6, 2002)

15. Letter from New Mexico Environment Department to Larry Messinger, Mustang Energy Corporation (Dec. 23, 2002)

16. Letter from New Mexico Environment Department to Larry Messinger, Mustang Energy Company (Aug. 29, 2003)

17. Major Environmental Aspects of Gasification-Based Power Generation Technologies, Dec 2002, Table 1-7, page 1-26

18. Smith, R.G., "Eastman Chemical Plant Kingsport Plant Chemicals from Coal Operations,1983-2000," 2000 Gasification Technologies Conference

19. O'Keefe, L. and Sturm, K., "Clean Coal Technology Options - A Comparison of IGCC vs. Pulverized Coal Boilers," presentation to the 2002 Gasification Technologies Conference, October 2002

20. O'Keefe, Luke, et al. A Single IGCC Design for Variable CO2 Capture

21. National Coal Council, Increasing Electricity Availability from Coal-Fired Power Plants in the Near Term, p. 20 (May 2001)

22. "The Cost of Mercury Removal in an IGCC Plant," US DOE, NETL, September 2002

23. "IGCC's Environmental and Operational Capabilities Today," Workshop on Gasification Technologies, June 8, 2004, David L. Denton (Eastman Gasification Services Company)

24. Northampton Generating Station Permit

25. Longview Power Plant Permit

26. Trimble County Generating Station Permit

27. Intermountain Power Plant Permit

28. Sevier Power Plant Permit

29. August 8, 2001 Minor Permit Amendment to Big Stone I's Title V Permit

30. Statement of Basis for August 8, 2001 Minor Permit Amendment to Big Stone I's Title V Permit

31. FORTRAN Code to Meteorological Data Processing Program

32. Haul Road Emissions Spreadsheet

33. Otter Tail's January 2001 Response to EPA's 12/00 Section 114 Information Request

34. Otter Tail's February 2001 Response to EPA's 12/00 Section 114 Information Request

35. Otter Tail's March 2001 Response to EPA's 12/00 Section 114 Information Request

36. Otter Tail's March 2003 Response to EPA's 12/00 Section 114 Information Request

37. Statement of Basis, Prevention of Significant Deterioration Permit, Otter Tail Power Company - Big Stone II, Big Stone City South Dakota (April 2006).

38. Draft Prevention of Significant Deterioration Permit, Otter Tail Power Company - Big Stone II, Big Stone City South Dakota (March 2006)